UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 1-10499

NorthWestern Energy

NORTHWESTERN CORP

(Exact name of registrant as specified in its charter)

Delaware	**46-0172280**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3010 W. 69th Street Sioux Falls South Dakota	**57108**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 605-978-2900

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock	NWE	Nasdaq Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. Yes ☐ No ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to the previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $3,308,859,038 computed using the last sales price of $58.93 per share of the registrant’s common stock on June 30, 2022, the last business day of the registrant’s most recently completed second fiscal quarter.

As of February 10, 2023, 59,768,222 shares of the registrant’s common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference

Certain sections of our Proxy Statement for the 2023 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Annual Report, relating to our current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Words or phrases such as “anticipates," “may," “will," “should," “believes," “estimates," “expects," “intends," “plans," “predicts," “projects," “targets," “will likely result," “will continue" or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, our examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- adverse determinations by regulators, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, could have a material effect on our liquidity, results of operations and financial condition;
- the impact of extraordinary external events and natural disasters, such as a wide-spread or global pandemic, geopolitical events, earthquake, flood, drought, lightning, weather, wind, and fire, could have a material effect on our liquidity, results of operations and financial condition;
- acts of terrorism, cybersecurity attacks, data security breaches, or other malicious acts that cause damage to our generation, transmission, or distribution facilities, information technology systems, or result in the release of confidential customer, employee, or Company information;
- supply chain constraints, recent high levels of inflation for product, services and labor costs, and their impact on capital expenditures, operating activities, and/or our ability to safely and reliably serve our customers;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase operating costs or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption “Risk Factors” which is part of the disclosure included in Part I, Item 1A of this Annual Report on Form 10-K.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Annual Report on Form 10-K, our reports on Forms 10-Q and 8-K, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate, or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Annual Report on Form 10-K, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Annual Report on Form 10-K or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

Unless the context requires otherwise, references to "we," "us," "our," "NorthWestern Corporation," "NorthWestern Energy," and "NorthWestern" refer specifically to NorthWestern Corporation and its subsidiaries.

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

Capacity - The amount represents the maximum output of electricity a generator can produce and is related to peak demand. We must maintain a level of available capacity sufficient to meet peak demand with a sufficient reserve.

Commercial Customers - Consists primarily of main street businesses, shopping malls, grocery stores, gas stations, bars and restaurants, professional offices, hospitals and medical offices, motels, and hotels.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

DGGS - The Dave Gates Generating Station at Mill Creek, a 150 MW natural gas fired facility.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity risk).

Industrial Customers - Consists primarily of manufacturing and processing businesses that turn raw materials into products.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Midcontinent Independent System Operator (MISO) - MISO is a nonprofit organization created in compliance with FERC as a regional transmission organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets, and managing the ancillary market.

Midwest Reliability Organization (MRO) - MRO is one of eight regional electric reliability councils under NERC.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Nameplate Capacity - The intended full-load sustained output of a generating facility. Nameplate capacity is the number registered with authorities for classifying the power output of a power station usually expressed in MWs.

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) -The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), a QF sells power to a regulated utility at a price agreed to by the parties or determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to generate its own power or buy power from another source.

Reserve Margin - The difference between available capacity and peak demand used in system planning to ensure adequate power supply. A positive percentage indicates the electric system has excess capacity while a negative percentage indicates the electric system is unable to meet peak demand without using market resources.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

Secured Overnight Financing Rate (SOFR) - A broad measure of the cost of borrowing cash overnight collateralized by Treasury securities.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Southwest Power Pool (SPP) - A nonprofit organization created in compliance with FERC as a regional transmission organization to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. SPP also serves as a regional electric reliability entity under NERC.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Tolling Contract - An arrangement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for a pre-established fee.

Transmission - The flow of electricity from generating stations and interconnections with other systems over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - A federal power-marketing administration and electric transmission agency established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - A basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above 65 degrees Fahrenheit.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

ITEM 1. BUSINESS

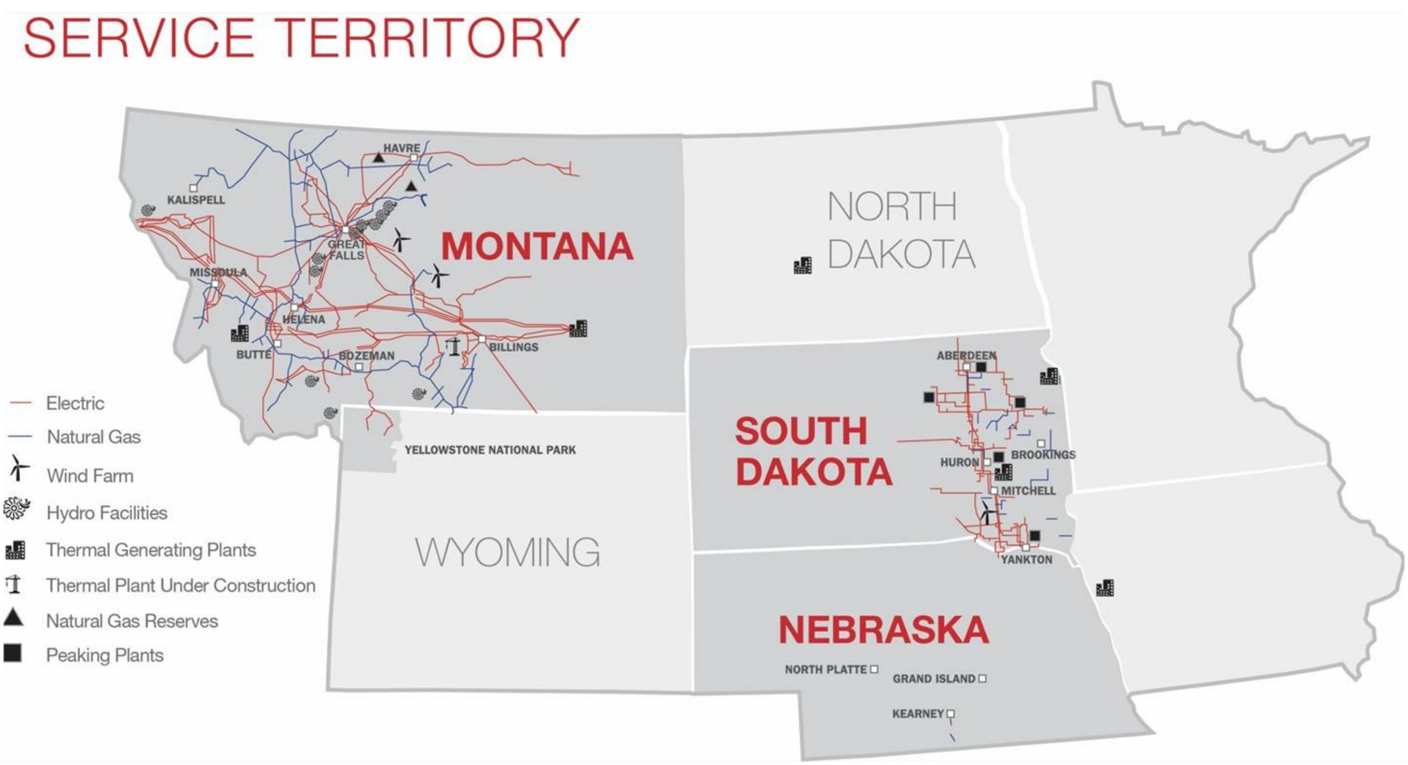
OVERVIEW

NorthWestern Energy - Delivering a Bright Future

NorthWestern Corporation, doing business as NorthWestern Energy, provides essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. We work to deliver safe, reliable, and innovative energy solutions that create value for customers, communities, employees, and investors. We do this by providing low-cost and reliable service performed by highly-adaptable and skilled employees. We provide electricity and / or natural gas to approximately 764,200 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. We have provided service in South Dakota and Nebraska since 1923 and in Montana since 2002.

We manage our businesses by the nature of services provided, and operate principally in three business segments: electric utility operations; natural gas utility operations; and all other, which primarily consists of unallocated corporate costs. Our electric utility operations include the generation, purchase, transmission and distribution of electricity, and our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our customer base consists of a mix of residential, commercial, and diversified industrial customers.

Our electric and natural gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our utility operations are seasonal and weather patterns can have a material impact on operating performance. Consumption of electricity is often greater in the summer and winter months for cooling and heating, respectively. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season.



Environmental, Social and Governance

We are focused on meeting current energy infrastructure and service needs at a reasonable and fair cost for today's customers while ensuring the ability to meet the needs of tomorrow's customers. "Sustainability" requires meeting economic, societal, and environmental objectives. As a provider of essential infrastructure and service, a sustainable enterprise is vital to our customers and communities, as well as to our investors and employees.

Over the past 100 years, we have maintained our commitment to provide customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. Over time, we have increased our environmental sustainability efforts and our access to carbon-free energy resources. In February 2022, we made a commitment to achieving Net-Zero by the year 2050 for Scope 1 and Scope 2 carbon and methane emissions. Our Scope 1 emissions are primarily from owned electric generation plants, fugitive emissions from our natural gas production, gathering, transmission and distribution systems and company owned transportation fleet. Our Scope 2 emissions are primarily from the electric and natural gas utilized to heat, cool and power our offices, warehouses and other facilities.

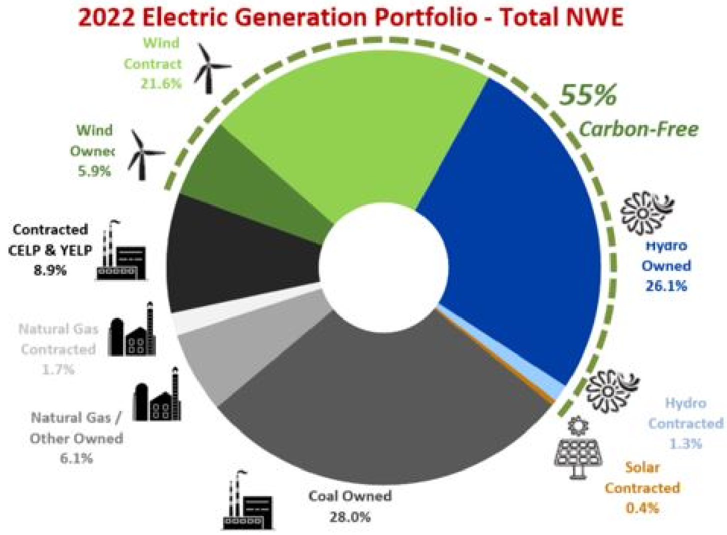
We currently own a mix of clean and carbon-free energy resources balanced with traditional energy sources that are necessary for us to deliver affordable and reliable electricity to our customers 24/7. In 2022, approximately 55 percent of our retail needs originated from carbon-free resources, compared to approximately 39 percent (Source: U.S. Energy Information Administration, 2022 Annual Energy Review, Electricity Net Generation: Electric Power Sector) for the total U.S. electric power industry in 2021. While we added additional carbon-free resources in 2022, our total output from carbon-free resources decreased from 56 percent in 2021 to 55 percent in 2022 due to our fossil fuel resources being dispatched at a higher percentage than in 2021. We do not receive all of the related Renewable Energy Credits (RECs) from our contracted electric supply resources and periodically sell RECs produced by our own carbon-free energy resources. The owner of the RECs claims the renewable attributes of the energy. Our resource mix does not represent the actual energy delivered to our customers. Market purchases and sales fill the gap between resources and customer demand.

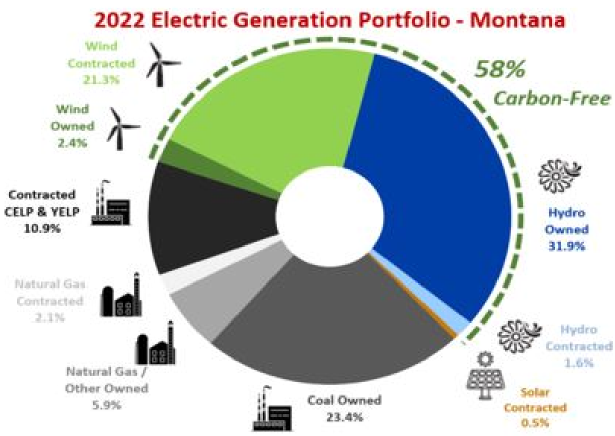
We are a fully regulated provider of critical infrastructure and essential services. Therefore, our success in meeting our obligations to our customers and the communities we serve depends on public policy. We believe that policy makers in the states we serve are committed to reliable, adequate, and affordable service, and a strong customer focus. We support policies that enable investment in critical infrastructure and responsible stewardship.

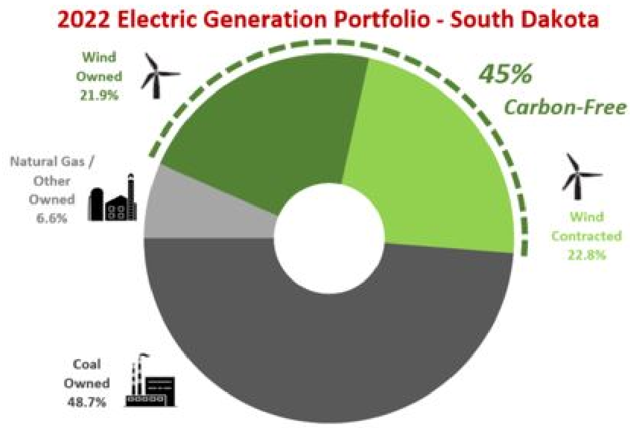
We believe that technological advancements, along with decreasing costs of carbon-free generation and the regionalization of intermittent generation, will significantly contribute to our goal of Net-Zero carbon emissions by 2050. The pace of transition to Net-Zero will depend on the timing of technological advancements, costs, and retirement of our existing coal fleet.

In South Dakota and Montana, we develop an Integrated Resource Plan (IRP) every two and three years, respectively. These IRPs, which are presented to our state regulatory commissions, identify resource needs, known and expected risks, as well as key variables to be used in evaluating resources. We then undertake a transparent resource solicitation process, run by an independent third party, to evaluate the least cost resources that address key risks and needs identified by the IRP. All generation types have the opportunity to participate in our Request for Proposals (RFP). Therefore, the specific resources that will be acquired to meet future need are dependent upon our current and future IRPs and the RFP process, in conjunction with the actions of our regulators during the regulatory process..

For a more detailed description of our environmental, social, governance and sustainability activities, please visit our company website at https://www.northwesternenergy.com. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.







Based on MWh's supplied from owned & long-term contracted resources.

Contracted energy from Colstrip Energy Limited Partners (CELP), Yellowstone Energy Limited Partners (YELP) as well as a majority of the contracted wind, hydro and solar are federally mandated Qualifying Facilities, as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA).

MONTANA ELECTRIC OPERATIONS

Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73 percent of Montana's land area. During 2022, we delivered electricity to approximately 398,200 customers in 221 communities and their surrounding rural areas, 11 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2022, by category, residential, commercial, industrial, and other sales accounted for approximately 45%, 46%, 5%, and 4%, respectively, of our Montana retail electric utility revenue.

Transmission and Distribution

Our electric system is composed of high voltage transmission lines and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 500 kV	497
Miles of 230 kV	987
Miles of 161 kV	1,184
Miles of 115 kV and lower voltage	3,929
Total Miles of Electric Transmission Lines	**6,597**
Electric Distribution Lines	
Miles of overhead line	13,276
Miles of underground line	5,258
Total Miles of Electric Distribution Lines	**18,534**
Total Transmission and Distribution Substations	**394**

In addition to delivering energy to distribution systems to serve customers, we also transmit electricity for nonregulated entities owning generation, and utilities, cooperatives, and power marketers serving the Montana electricity market. Our total control area peak demand reached a new all-time peak of approximately 2,073 MWs on December 22, 2022. Our control area average demand for 2022 was approximately 1,379 MWs per hour, with total energy delivered of more than 12.08 million MWHs.

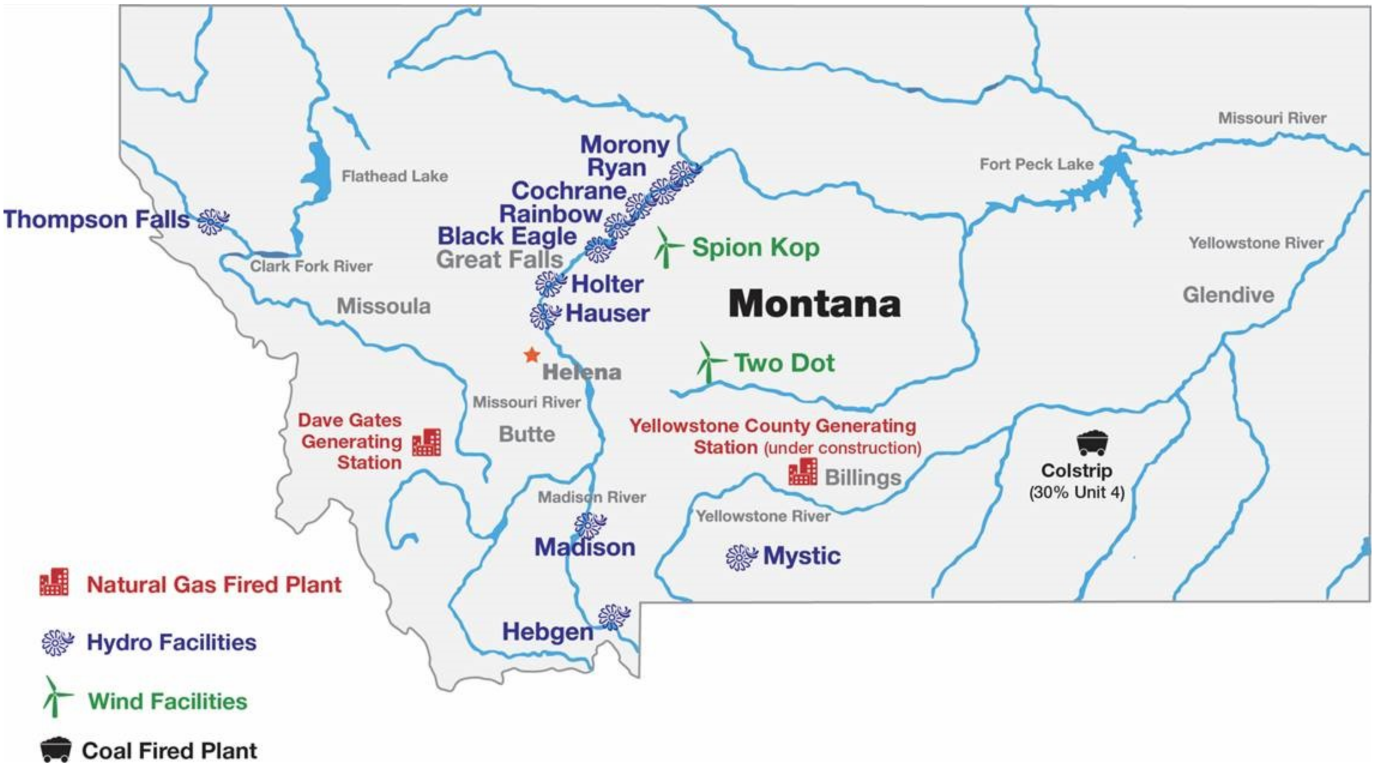
Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie Ltd. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the western power system. We provide wholesale transmission service and firm and non-firm transmission services for eligible transmission customers pursuant to our FERC Open Access Transmission Tariff.

Electric Supply

Our annual retail electric supply load requirements average approximately 750 MWs, with a peak load of approximately 1,250 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties.

Owned generation resources supplied approximately 65 percent of our retail load requirements for 2022. We expect that approximately 65 percent of our retail obligations will be met by owned generation resources in 2023. In addition, we have contracts with QFs totaling 469 MWs of nameplate capacity, including 87 MWs from waste petroleum coke and waste coal, 268 MWs from wind, 17 MWs from hydro, and 97 MWs from solar projects. We have several other long-term power purchase agreements including contracts for 135 MWs nameplate capacity from wind generation, 100 MWs from the British Columbia hydro system, 52 MWs of natural gas generation, and 21 MWs of seasonal base-load hydro supply. On average, our owned and long-term contracted resources are expected to provide enough energy to meet our retail energy load requirements in 2023. Load requirements during peak demand in excess of our owned and long-term contracted resources will be satisfied with market purchases.

Owned Generation Facilities



Details of these generating facilities are described in the following tables.

Hydro Facilities	COD	River Source	FERC License Expiration	Owned MW
Black Eagle	1927	Missouri	2040	23
Cochrane	1958	Missouri	2040	62
Hauser	1911	Missouri	2040	21
Holter	1918	Missouri	2040	50
Madison	1906	Madison	2040	12
Morony	1930	Missouri	2040	49
Mystic	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	64
Ryan	1915	Missouri	2040	72
Thompson Falls	1915/1995	Clark Fork	2025	94
Total[(1)]				**459**

(1) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, which is storage generation.

Other Facilities	Fuel Source	Ownership Interest	Owned MW
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	30%	222
DGGS, located near Anaconda, Montana	Natural Gas & Liquid Fuel	100%	150
Spion Kop Wind, located in Judith Basin County in Montana	Wind	100%	40
Two Dot Wind, located in Wheatland County in Montana	Wind	100%	11

Colstrip Unit 4 provides base-load supply and is operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. We have a reciprocal sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party is responsible for its own fuel-related costs. Colstrip Unit 4 is supplied with fuel from adjacent coal reserves under a coal supply agreement in effect through 2025. See *Item 1A Risk Factors* "Regulatory, Legislative and Legal Risks" for further discussion regarding the service life of generation facilities.

Resource Planning

Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. We filed our latest IRP with the MPSC in August 2019 and supplemented that plan in December 2020. Both filings projected generation capacity deficits and negative reserve margins. Since that time, we have been working to address the deficit with a combination of owned resources and long-term capacity contracts as well as short-and-intermediate term capacity contracts. We expect to file an updated IRP during the first quarter of 2023.

We issued an all-source competitive solicitation request in January 2020 for peaking and flexible capacity to be available for commercial operation beginning in 2023. The competitive solicitation resulted in a 100 MW, 5-year purchase of capacity from a market participant and the development of the 175 MW Yellowstone County Generating Station, which is currently under construction. In addition to our responsibility to meet peak demand, national NERC reliability standards increased the need for us to have greater dispatchable generation capacity available and be capable of increasing or decreasing output to address intermittent generation such as wind and solar. Our generation portfolio is a balanced mix of energy and capacity resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet our obligation to serve retail customers while maintaining reliability.

Western Energy Imbalance Market

We entered the Western Energy Imbalance Market (EIM), operated by the California Independent System Operator, on June 16, 2021. We added EIM transfer capability with Bonneville Power Administration, Avista Corp, and Tacoma Power in 2022, in addition to our existing EIM transfer capability with PacifiCorp and Idaho Power Company.

SOUTH DAKOTA ELECTRIC OPERATIONS

Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties. We provide retail electricity to more than 64,700 customers in 116 communities in South Dakota. In 2022, by category, residential, commercial and other sales accounted for approximately 38%, 60%, and 2%, respectively, of our South Dakota retail electric utility revenue.

Transmission and Distribution

Our electric system includes high voltage transmission and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 345 kV	25
Miles of 230 kV	18
Miles of 115 kV and lower voltages	1,265
Total Miles of Electric Transmission Lines	**1,308**
Electric Distribution Lines	
Miles of overhead line	1,619
Miles of underground line	723
Total Miles of Electric Distribution Lines	**2,342**
Total Transmission and Distribution Substations	**121**

Our South Dakota system is interconnected with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We also have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative.

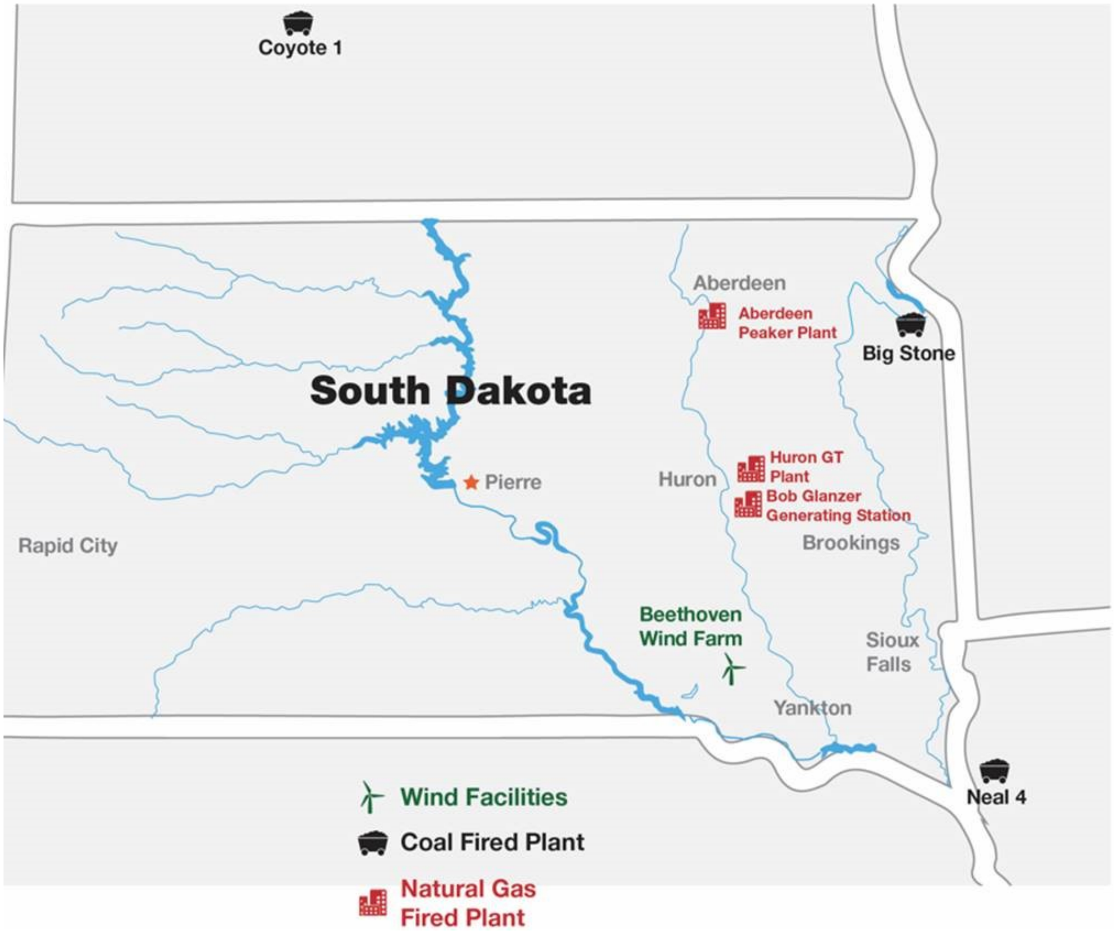
We are a transmission-owning member in the SPP, with our transmission facilities residing in zone 19 of the SPP footprint. Each year, we review all new or modified transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. This annual update goes into effect on April 1st each year. To date, we have transferred control of 333 line miles of 115 kV facilities and over 158 line miles of 69 kV facilities. Along with SPP, our South Dakota facilities have ties to MISO. We have grandfathered agreements in MISO, which provide us the access to move the power from the Coyote, Big Stone, and Neal power plants to our customers. Along with operating the transmission system, SPP also coordinates regional transmission planning for all of its members on an annual basis through its Integrated Transmission Planning (ITP) process. Our annual participation in the ITP process includes model development, system needs assessment, and solution development to address identified needs.

Electric Supply

Our annual retail electric supply load requirements average approximately 200 MWs, with a peak load of 340 MWs, and are supplied by owned and contracted resources and market purchases. We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We are a member of the SPP. As a market participant in SPP, we buy and sell wholesale energy and reserves in both day-ahead and real-time markets through the operation of a single, consolidated SPP balancing authority. We and other SPP members submit into the SPP market both offers to sell our generation and bids to purchase power to serve our load. SPP optimizes next-day and real-time generation dispatch across the region and provides participants with greater access to economic energy. Marketing activities in SPP are handled for us by a third-party provider acting as our agent.

Electric supply resources include 211 MWs from jointly owned coal plants and 138 MWs from two natural gas-fired plants. Additional resources include several peaking units and an 80 MW wind facility. We also purchase the output of four wind projects, three of which are QFs, under power purchase agreements. Actual output for our wind resources varies based upon weather conditions.

Owned Generation Facilities



Details of our generating facilities are described further in the following chart:

Generation Facilities	Fuel Source	Ownership Interest	Owned MW
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	23.4%	111
Aberdeen Generating Units No. 1 and 2, located near Aberdeen, South Dakota	Natural gas & Liquid Fuel	100.0%	80
Beethoven Wind Project, located near Tripp, South Dakota	Wind	100.0%	80
Bob Glanzer Generating Station, located near Huron, South Dakota	Natural Gas	100.0%	58
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	8.7%	57
Coyote Electric Generating Station, located near Beulah, North Dakota	Lignite coal	10.0%	43
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas	100.0%	17
Total			**446**

We completed the construction of the 58 MW Bob Glanzer Generating Station in the summer of 2022. This plant includes flexible reciprocating internal combustion engines near Huron, South Dakota.

The Big Stone, Coyote and Neal plants are owned jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure, and we are not the operator of any of these plants. Based on our ownership interest, we are entitled to a proportionate share of the capacity of our jointly owned plants and are responsible for a proportionate share of the operating costs.

The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal Unit No. 4 and Big Stone receive their fuel supply via rail. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

Resource Planning

We have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis.

We submitted a plan to the SDPUC in September of 2022 to provide for the modernization of our generating fleet, which is focused on improving reliability and flexibility.

NATURAL GAS OPERATIONS

Montana

Our regulated natural gas utility business in Montana includes production, storage, transmission and distribution. During 2022, we distributed natural gas to approximately 209,100 customers in 118 Montana communities over a system that consists of approximately 5,100 miles of underground distribution pipelines. We also serve several smaller distribution companies that provide service to approximately 37,000 customers. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 47 Bcf during the year ended December 31, 2022.

Miles of Natural Gas Transmission	**2,235**
Miles of Natural Gas Distribution	**5,099**
City Gate Stations	**135**

We have connections in Montana with four major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, and Spur Energy. Twelve compressor sites provide more than 46,000 horsepower on the transmission line and an additional 15,000 horsepower at our storage fields, capable of moving more than 360,000 dekatherms per day. In addition, we own and operate two transmission pipelines through our subsidiaries, Canadian-Montana Pipe Line Corporation and Havre Pipeline Company, LLC.

Natural gas is used primarily for residential and commercial heating, and as fuel for two electric generating facilities. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for the year ended December 31, 2022, were approximately 23.2 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2022, were approximately 5.7 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts, short-term market purchases and owned production. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in significant natural gas producing regions in the United States, primarily the Rocky Mountains (Colorado), Montana, and Alberta, Canada.

Owned Production and Storage - Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value: as we own these assets, which are regulated, our customers are protected from potential price spikes in the market. As of December 31, 2022, these owned reserves totaled approximately 35.1 Bcf and are estimated to provide approximately 3.0 Bcf in 2023, or approximately 13 percent of our expected annual retail natural gas load in Montana. In addition, we own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.85 Bcf and maximum aggregate daily deliverability of approximately 194,000 dekatherms.

South Dakota and Nebraska

We provide natural gas to approximately 49,200 customers in 80 South Dakota communities and approximately 43,000 customers in 4 Nebraska communities. In South Dakota, we also transport natural gas for nine gas-marketing firms and three large end-user accounts. In Nebraska, we transport natural gas for four gas-marketing firms and one large end-user account. We delivered approximately 31.0 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.8 Bcf of third-party transportation volume on our Nebraska distribution system during 2022.

Miles of Natural Gas Transmission	**55**
Miles of Natural Gas Distribution	**2,545**

Our South Dakota natural gas supply requirements for the year ended December 31, 2022, were approximately 6.3 Bcf. We contract with a third party under an asset management agreement to manage transportation and storage of supply to minimize cost and price volatility to our customers. In Nebraska, our natural gas supply requirements for the year ended December 31, 2022, were approximately 4.4 Bcf. We contract with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities. To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our customers.

Municipal Natural Gas Franchise Agreements

We have municipal franchises to provide natural gas service in the communities we serve. The terms of the franchises vary by community. Our Montana franchises typically have a fixed 10-year term and continue for additional 10-year terms unless and until canceled, with 5 years notice. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We continue to serve those customers while we obtain formal renewals. During the next five years, nine of our Montana franchises could expire by action taken by the franchises' city or town, which account for approximately 9,077 or four percent of our Montana natural gas customers. Six of our South Dakota franchises and one franchise in Nebraska, which account for approximately 27,104 or 29 percent of our South Dakota and Nebraska natural gas customers, are scheduled to reach the end of their fixed term during the next five years. We do not anticipate termination of any of these franchises.

GOVERNMENT REGULATION

NorthWestern's provision of utility service is regulated by the MPSC, the SDPUC, the NPSC, and the FERC. NorthWestern is also regulated by many other state and federal agencies. For example, because NorthWestern's operations impact land, waterways and the air, NorthWestern is subject to a wide range of regulations administered by the federal Environmental Protection Agency, the U.S. Fish & Wildlife Service, and parallel state agencies regulating environmental and natural resources in Montana, South Dakota and Nebraska. Another example relates to NorthWestern's provision of natural gas service. The U.S. Department of Transportation through the Pipeline and Hazardous Materials Safety Administration, along with its state partners, regulates natural gas pipeline and natural gas storage field safety. As a publicly-traded company, we are subject to the SEC's requirements regarding financial reporting, disclosures, and laws and regulations protecting investors. We are subject to the Occupational Safety and Health Administration (OSHA), which regulates workplace safety. We are also subject to local zoning laws and regulations.

As detailed below, the rates we charge our utility customers are set through approval by the regulatory commission with jurisdiction in each of our respective service territories. Base rates are the rates that are intended to allow us the opportunity to collect from our customers total revenues (revenue requirements) equal to our cost of providing delivery and rate-based supply services, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates and cost tracking clauses. We may ask the respective regulatory commission to increase base rates from time to time. Rate increase requests are normally reviewed based on historical data and any resulting approvals may not always keep pace with increasing costs. For more information on current regulatory matters, see Note 3 - Regulatory Matters, to the Consolidated Financial Statements.

The following is a summary of our rate base (amounts we earn a return on) and authorized rates of return in each jurisdiction, estimated as of December 31, 2022:

Jurisdiction and Service	Implementation Date	Authorized Rate Base (millions)	Year-end Estimated Rate Base (millions)	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Montana electric delivery and production(1)	April 2019(4)	$2,030.1	$2,675.8	6.92%	9.65%	49.38%
Montana - Colstrip Unit 4	April 2019	304.0	271.3	8.25%	10.00%	50.00%
Montana natural gas delivery and production(2)	September 2017(4)	430.2	643.3	6.96%	9.55%	46.79%
Total Montana		$2,764.3	$3,590.4			
South Dakota electric(3)	December 2015	$557.3	$799.6	7.24%	n/a	n/a
South Dakota natural gas(3)	December 2011	65.9	97.8	7.80%	n/a	n/a
Total South Dakota		$623.2	$897.4			
Nebraska natural gas(3)	December 2007	$24.3	$49.9	8.49%	10.40%	n/a
		$3,411.8	$4,537.7			

(1) The revenue requirement associated with the FERC regulated portion of Montana electric transmission and ancillary services are included as revenue credits to our MPSC jurisdictional customers. Therefore, we do not separately reflect FERC authorized rate base or authorized returns.
(2) The Montana gas revenue requirement includes a step down which approximates annual depletion of our natural gas production assets included in rate base.
(3) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.
(4) On August 8, 2022, we filed a Montana electric and natural gas rate review filing (2021 test year) requesting an increase to our authorized rate base, return on equity, and equity level in our capital structure. We expect a final order regarding this rate review in 2023.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return.

Electric Supply Tracking Mechanism - The Power Cost and Credit Adjustment Mechanism (PCCAM) tracks, for recovery through utility rates, the cost of power purchased and fuel used to generate electricity. The PCCAM incorporates sharing of a portion of the business risk or benefit associated with the energy supply costs with 90 percent of the variance above or below the established base revenues and actual costs collected from or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if electric supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

Natural Gas Supply Tracker - Rates for our Montana natural gas supply are set by the MPSC. Certain supply rates are adjusted on a monthly basis for volumes and costs during each July to June 12-month tracking period based on the established base revenues and actual costs collected from customers or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if natural gas supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

***Montana Property Tax Tracker* -** We file an annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflects the incremental property taxes since our last base rate filing adjusted for the associated income tax benefit.

***Fixed Cost Recovery Mechanism Pilot* -** In our 2018 Montana electric rate settlement, the MPSC approved a Fixed Cost Recovery Mechanism Pilot (FCRM), intended to decouple our recovery of fixed, test-year based transmission, distribution, and production costs from sales of energy. At our request, the MPSC delayed implementation of the pilot until modifications are considered in our pending 2022 Montana electric and natural gas rate review filing.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. On a daily basis, we monitor usage for these customers and balance it against their respective supply agreements.

An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the proposed rate change if the affected communities representing more than 50 percent of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been approved by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for biannual, or more often if needed, adjustments based on changes in gas supply and interstate pipeline transportation costs.

FERC Regulation

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service and electricity sold at wholesale, hydro licensing and operations, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability standards, among other things. Under FERC's open access transmission policy, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct for Transmission Providers.

Our Montana wholesale transmission customers, such as cooperatives, industrial customers, and other customers that have third-party commodity supply providers, are served under our OATT, which is on file with FERC. The OATT defines the terms, conditions, and rates of our Montana transmission service, including ancillary services. Our South Dakota transmission operations are in the SPP, and transmission service is provided under the SPP OATT.

Our natural gas transportation pipelines are generally not subject to FERC's jurisdiction, although we are subject to state regulation. We conduct limited interstate transportation in Montana and South Dakota that is subject to FERC jurisdiction, and FERC has allowed the MPSC and SDPUC to set the rates for this interstate service. We have capacity agreements in South Dakota and Nebraska with interstate pipelines that are also subject to FERC jurisdiction.

Our hydroelectric generating facilities are licensed by the FERC and operated under the terms of those licenses and FERC regulations. In connection with the relicensing of these generating facilities, applicable law permits the FERC to issue a new license to the existing licensee, to a new licensee, or alternatively allows the U.S. government to take over the facility. If the existing licensee is not relicensed, it is compensated for its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages to other property affected by the lack of relicensing.

***Reliability Standards* -** We must comply with the standards and requirements that apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC-approved mandatory reliability standards within their respective regions. We expect that the reliability standards will continue to evolve and change as a result of modifications, guidance, and clarification following industry implementation and ongoing audits and enforcement.

COMPETITION

We are subject to public policies that promote competition and development of energy markets. Our industrial and large commercial customers have the ability to choose their electric supplier and may generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region. Customers have the opportunity to supply their own power with distributed generation including solar generation, and in Montana, can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. These incentives and federal tax subsidies make distributed generating resources viable potential competitors to our electric service business.

In addition, the FERC has continued to promote competitive wholesale markets through open access transmission and other means. Our wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems to serve their load. There is also competition for available transmission capacity to meet our electric supply needs to serve customers.

ENVIRONMENTAL

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, and protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

To this end, the Biden Administration set ambitious goals to address climate change, including the goal of a carbon free power sector by 2035 and net zero carbon emissions by 2050. Executive Orders issued by the Biden Administration included initiatives and directives intended to reduce greenhouse gas (GHG) emissions, address climate change and decarbonize the energy sector. These Executive Orders established climate considerations as key components of United States foreign policy and national security, established a White House Office of Domestic Climate policy as well as a National Climate Task Force, called for agency heads to identify any fossil fuel subsidies provided by their agencies and to take steps to ensure that federal funding is not directly subsidizing fossil fuels, and directed agencies to immediately review all regulations proposed or finalized by the Trump Administration that conflict with the Biden Administration’s objectives and to take action to rescind or revise those rules. Months later, President Biden officially rejoined the Paris Accord. More recently, President Biden's Infrastructure Investment and Jobs Act and Inflation Reduction Act of 2022 contain significant climate initiatives. These initiatives present opportunities for federal grants and tax incentives intended to hasten the future economy-wide deployment of various GHG reducing technologies and approaches.

Implementation of these initiatives and directives has the potential to limit or curtail our operations, including the burning of fossil fuels at our coal-fired power plants. While we strive to comply with all environmental regulations applicable to our operations, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to energy and environmental laws and regulations, or new administrative or judicial interpretations or enforcement decisions regarding them.

Estimated capital expenditures for environmental control facilities in 2023 and 2024 are not expected to be material. For more information on environmental regulations and contingencies and related capital expenditures, see Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements.

CORPORATE INFORMATION AND WEBSITE

We were incorporated in Delaware in November 1923. Our Internet address is https://www.northwesternenergy.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.

HUMAN CAPITAL RESOURCES

Our ability to achieve the objectives of our business strategy and serve our customers within our service territory depends on employing skilled individuals at all levels of our organization. We aspire to be an employer of choice by offering competitive salaries and benefits, providing a safe working environment, valuing diversity, fostering inclusion and encouraging a healthful work–life balance. Our success comes when employees feel empowered to take initiative, voice their opinions, and build on their experiences within our company and our communities.

As of December 31, 2022, we had 1,530 employees. Of these, 1,232 employees were in Montana and 298 were in South Dakota or Nebraska. Of our Montana employees, 454, or 37 percent, were covered by seven collective bargaining agreements involving five unions. During 2022, all seven collective bargaining agreements were renegotiated and a 4-year ratified agreement was reached. Each of the Montana collective bargaining agreements will now expire in 2026. Of our South Dakota and Nebraska employees, 165, or 56 percent, are covered by a collective bargaining agreement renegotiated in 2021 that expires in 2025. We consider our relations with employees to be good.

Talent Management

Attraction and retention of skilled employees is key to our ongoing success. We invest resources in maintaining a culture that supports the ongoing development of our workforce. This includes an integrated learning and performance management system which includes annual performance reviews that link goals and competencies together so that managers are able to provide a holistic view to employees in regards to their performance against goals as well as key competencies as they relate to their role in the organization. This process provides opportunities to develop and enhance skills and knowledge, and enables our employees to grow professionally and perform their duties in a safe and efficient manner. This structured training and development is intended to provide employees a consistent learning experience, and maximizes learning retention and background knowledge. We offer tuition reimbursement to promote continued professional growth for current employees, and a scholarship program for students attending universities, colleges, and technical schools in our service area to assist in developing current and future skills sets needed by our employees. We support annual pre-apprentice scholarships, recruit and hire suitable candidates from the program, serve as industry advisors on the program board and have donated training assets to support the program.

Compensation and Benefits

Our overarching compensation philosophy is structured to be consistent with our peers, and to align the long term interests of our employees, executives, shareholders, and customers so the pay appropriately reflects performance in achieving financial and non-financial operating objectives. We offer a competitive pay and benefits package, which is benchmarked on an annual basis to external market data. Beyond base pay and incentive compensation, we offer competitive, cost-effective, and well-rounded benefits, which aligns with our desire to be an employer of choice. From considerable employer retirement contributions, to generous paid time off (PTO), to health care and well-being programs, our benefits are designed to meet the varied needs of our employees.

We are committed to internal pay equity, and the Human Resources Committee of the Board of Directors monitors the relationship between the pay our executive officers receive and the pay our non-managerial employees receive. During 2022 and 2021, the compensation for our CEO was approximately 26 and 28 times, respectively, the compensation of our median employee.

We believe that a significant portion of an executive's pay should be at risk in the form of performance-based incentive awards that are only paid if the individual and company performance targets are met. For 2022, approximately 79 percent of the targeted compensation of our CEO and about 65 percent of the targeted compensation of our other named executive officers is at risk in the form of performance-based incentive awards or time-based awards tied to the value of equity. Our Board of Directors establishes the metrics and targets for these incentive awards, based upon advice from the Board of Directors' independent compensation consultant.

We engage nationally recognized outside compensation and benefits consulting firms to independently evaluate the effectiveness of our compensation and benefits programs and to provide benchmarking against our peers within the industry.

Diversity

We believe a diverse and inclusive workforce adds value and helps us succeed in an ever-changing environment. By embracing diversity and fostering inclusion, we aim to enable each employee, executive, and director to contribute fully to the company. We believe diversity is important because varied perspectives expand our ability to bring unique professional experiences to our business. Diversity in the workforce will be considered when relevant to hiring, promotions, work assignments, or other decisions related to the terms and conditions of employment. Our workforce reflects the relative diversity of our available talent in the communities we serve. Our employment data is tested annually by a third party as part of our Affirmative Action plan development to identify any needed corrective placement goals that are required. This testing determined that there is no current need to establish corrective placement goals in our plan.

We continue to maintain a diverse workforce, with an executive team that is 50% female and a board of directors that is 38% female and has one ethnically diverse member (13%). In addition, the equitable nature of our compensation practices has led to a low CEO to median employee ratio of 26 to 1. We have implemented methods to provide pay equity between our female and male employees performing equal or substantially similar work. We have engaged with a third party to review our pay equity between our male and female employees, share the results with our Board of Directors, and take corrective action as necessary. Our most recent study was performed in 2019, with no corrective action required.

Health and Safety

As stewards of critical infrastructure, providers of energy service, and members of the communities we serve, our priority is the health and safety of our employees and customers. Safety and health are considered and integrated into all work activities. We monitor several different key areas relating to safety philosophies and policies. These key metrics include the recordable incident rate (number of work-related injuries per 100 employees for a one-year period) and lost time incident rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). During the years ended December 31, 2022 and 2021, our recordable incident rates were 1.57 and 1.77 and lost time incident rates were 0.59 and 0.66 on a company wide basis. Our five-year average safety record for the year ended December 31, 2022 was better than our industry peer group's five-year average.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Executive Officer	Current Title and Prior Employment	Age[1]
Brian B. Bird	President and Chief Executive Officer and Director since January 2023; formerly President and Chief Operating Officer since February 2021 and Chief Financial Officer from December 2003 to February 2021. Mr. Bird also serves on the board of directors of a NorthWestern subsidiary.	60
Crystal D. Lail	Vice President and Chief Financial Officer since February 2021; formerly Vice President and Chief Accounting Officer since April 2020; and formerly Vice President and Controller from October 2015 to April 2020.	44
Michael R. Cashell	Vice President - Transmission since May 2011. Mr. Cashell serves on the board of directors of a NorthWestern subsidiary.	60
John D. Hines	Vice President - Supply and Montana Government Affairs since January 2018; formerly Vice President - Supply since May 2011.	64
Curtis T. Pohl	Vice President - Asset Management & Business Development since September 2022; formerly Vice President - Distribution since May 2011. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary.	58
Bobbi L. Schroeppel	Vice President - Customer Care, Communications and Human Resources since May 2009.	54
Jeanne M. Vold	Vice President - Technology since February 2021; formerly Business Technology Officer since 2012.	56
Jason C. Merkel	Vice President - Distribution since September 2022; formerly General Manager - Operations and Construction since 2007.	55
Cyndee S. Fang	Vice President - Regulatory Affairs since January 2023; formerly Director - Regulatory Affairs since March 2021; prior to joining the Company, she was Origination & Portfolio Design Manager from December 2020 to March 2021, Manager of Energy Research & Analysis from August 2018 to December 2020, and Manager of Customer Pricing from June 2017 to August 2018, in each case, for San Diego Gas and Electric Company, an electric and gas utility.	53
Shannon M. Heim	Vice President - General Counsel and Federal Government Affairs since January 2023; formerly Director, Regulatory Corporate Counsel since June 2020; and formerly Equity Shareholder at the law firm of Moss & Barnett, P.A. from 2017 to 2020.	50

(1) As of February 10, 2023.

Officers are elected annually by, and hold office at the pleasure of the Board of Directors (Board), and do not serve a "term of office" as such.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Regulatory, Legislative and Legal Risks

Our profitability depends on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We are subject to potential unfavorable litigation, and state and federal regulatory outcomes. To the extent our incurred costs are deemed imprudent by the applicable regulatory commissions or certain regulatory mechanisms are not available, we may not recover some of our costs or collect them in a timely manner, which could adversely impact our results of operations and liquidity.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and rates that we can charge customers. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital and rates are generally set through a process called a rate review (or rate case) in which the utility commission analyzes our costs incurred during a historical test year and decides whether they may be included in our base rates. In addition to formal general rate reviews, we also have cost tracking mechanisms that are intended to allow us to recover prudently incurred costs. There can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in rates that allow us the opportunity to earn our authorized return or provide for timely and full recovery of such costs. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. Differing schedules and regulatory practices between our state commissions and FERC expose us to the risk that we may not fully recover our costs due to timing of filings, specific calculations and issues such as cost allocation methodologies. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

Historically, in Montana we have often sought and received a determination from the MPSC that acquisitions or additions to our generating portfolio were "pre-approved," with subsequent investment subject to a later prudence determination. The Montana preapproval statute is currently the subject of litigation. If the preapproval statute is not ultimately upheld, there will be no explicit statutory mechanism that facilitates advanced approval of generating resource selection. Without preapproval, we may be subject to additional risk of non-recovery, which can increase debt costs and rates paid by customers.

We are also at risk of unfavorable litigation outcomes related to zoning and environmental permits. See discussion related to our Yellowstone County Generating Station below in "Management's Discussion and Analysis – Significant Trends and Regulation." Adverse litigation outcomes could delay or terminate projects, increase costs and impact our ability to service our customers.

We are subject to changing federal and state laws and regulations. Congress and state legislatures may enact legislation that adversely affects our operations and financial results.

We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing and the federal administration, the U.S. Congress, state legislatures and state administrations may enact and implement new laws and regulations that could adversely and materially affect us. For example, legislation and regulations may be enacted that require or facilitate alternative generation or storage which, in turn, could result in customers using less of our energy or facilities which could reduce our revenues and our growth opportunities. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. There can be no assurance that laws, regulations and policies will not be changed in ways that have a material adverse effect on our operations, financial condition, results of operations, and cash flows.

We are subject to extensive and changing energy, and environmental laws and regulations, including legislative, judicial, and regulatory responses to climate change, with which compliance may be difficult and costly.

Our operations are subject to laws and regulations imposed by federal, state and local government authorities regarding energy policy, permitting/siting for energy projects, climate change, the environment, air and water quality, GHG emissions, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements.

In response to recent regulatory and judicial decisions and international accords, GHG emissions, most significantly CO_2, could be restricted in the future as a result of federal or state legal requirements or litigation relating to GHG emissions. No rules are currently in effect that require us to reduce our GHG emissions. However, laws and regulations to which we must adhere change, and the Biden Administration's agenda includes a significant shift in environmental and energy policy, focusing on reducing GHG emissions and addressing climate change issues. Together, these actions reflect climate change issues and GHG emissions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing GHG emissions is reflected in legislation introduced in Congress. These initiatives could lead to new and revised energy and environmental laws and regulations, including tax reforms relating to energy and environmental issues. Any such changes, as well as any enforcement actions or judicial decisions regarding those laws and regulations, could result in significant additional compliance costs that would affect our future financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Such changes also could affect the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects.

Although previous attempts by the EPA to regulate GHG emissions from coal-fired plants have not succeeded, if GHG and/or methane regulations are implemented, compliance with carbon dioxide (CO_2) emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

To the extent that costs exceed our estimated environmental liabilities, or we are not successful in recovering remediation costs or costs to comply with the proposed or any future changes in rules or regulations, our results of operations and financial position could be adversely affected. Certain environmental laws and regulations also provide for substantial civil and criminal fines for noncompliance which, if imposed, could result in material costs or liabilities.

In addition, there is a risk of environmental damage claims from private parties or government entities. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

Early closure of our owned and jointly owned electric generating facilities due to environmental risks, litigation or public policy changes could have a material adverse impact on our results of operations and liquidity.

While a majority of our Company-wide electric supply portfolio is carbon-free, it does include fossil-fuel resources. Environmental advocacy groups, certain investors and other third parties oppose the operation of fossil-fuel generation, expressing concerns about the environmental and climate-related impacts from fossil fuels. This opposition may increase in scope and frequency depending on a number of variables, including the course of Federal and State laws and environmental regulations and the financial resources devoted to opposition efforts. These risks include litigation against us due to GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

In particular, as described more fully below in Note 18 - Commitments and Contingencies, we are a co-owner of Colstrip Unit 4. The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Talen and Puget Sound Energy (Puget), a co-owner of Colstrip, have entered into a transaction in which Puget will transfer its 25% project share in Units 3 and 4 to Talen. The anticipated closing date of the transaction is December 31, 2025. On September 12, 2022, Puget issued a notice of the transaction, triggering a 90 day timeframe in which we, or other co-owners could exercise rights of first refusal arising under the Ownership and Operation Agreement relating to these units (the O&O Agreement). The co-owners subsequently agreed to extend the time to exercise rights of first refusal until February 22, 2023. On January 16, 2023 we entered into an agreement with Avista Corporation pursuant to which it will transfer to us its 15% project share in Units 3 and 4 on December 31, 2025. Each of the co-owners will have 90 days following Avista's February 17, 2023 notice under the O&O Agreement, to exercise their rights of first refusal as to the Avista-NorthWestern transaction.

The closure by third parties of Billings area generation (Corette) and Colstrip Units 1 and 2 reducing supply, together with increased customer load and the lack of dispatchable replacement generation in eastern Montana, has accelerated concerns about potential difficulties in physically serving parts of Montana including the Billings area. We are executing on multi-year plans for upgrades to the Billings area substations and other delivery infrastructure, but the addition of dispatchable generation in the area is also critical to reliable service in eastern Montana.

Increased risks of regulatory penalties could negatively impact our business.

We must comply with established reliability standards and requirements including Critical Infrastructure Protection Reliability Standards, which apply to North American Electric Reliability Corporation (NERC) functions. NERC reliability standards protect the nations' bulk power system against potential disruptions from cyber and physical security breaches. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Penalties for the most severe violations can reach nearly $1.2 million per violation, per day. If a serious reliability incident or other incidence of noncompliance did occur, it could have a material adverse effect on our operating and financial results.

Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal or state agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs to our customers and decrease system reliability, limit our ability to make generation investments and adversely affect our business.

We are generally obligated under federal law to purchase power from certain QF projects, regardless of current load demand, availability of lower cost generation resources, transmission availability or market prices. Although some of these resources include a battery component, they are primarily intermittent generation whose prices may be in excess of market prices during times of lower customer demand, and may not be able to generate electricity during peak times. These resources typically do not meet the requirements set forth in our supply plans for resource procurement. These requirements to purchase supply that is inconsistent with customer need may have multiple impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources, negatively impacting our ability to make our own generation investments and increasing the likelihood that we will need to upgrade or build additional transmission facilities to serve QF projects. Any of these results would increase costs to customers and impact our investment plan. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs, those increased costs may negatively affect our liquidity, results of operations and financial condition.

In addition, requirements to procure power from these sources could impact our ability to make generation investments depending upon the number and size of QF contracts we ultimately enter into. The cost to procure power from these QFs may not be a cost effective resource for customers, or the type of generation resource needed, resulting in increased supply costs that are inconsistent with resource plans developed based on a lowest cost and least risk basis while placing upward pressure on overall customer bills. This may impact our investment plans and financial condition. Finally, the requirement to procure power from these QF sources may impact our transmission system and require additional transmission facilities to be developed in order to integrate these resources, which also can impact overall customer bills.

Operational Risks

Our electric and natural gas operations involve numerous activities that may result in accidents, fires, system outages and other operating risks and costs that are unique to our industry.

Inherent in our electric transmission and distribution and natural gas transmission and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, supply chain interruptions, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant. These risks could cause a loss of human life, facility shutdown or significant damage to property, service interruption, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others.

Fire risk is significant in the western United States, including in our service territory. Various factors in recent years have contributed to increasing fire risk including dead and dying trees, warmer air temperatures, drought, wind, forest management practices, and land management practices. These factors increase the risk of a fire in both forests and grasslands. In forested areas, this issue has been heightened by mountain pine beetle and other infestations weakening and killing trees in our service territory. Worsening conditions as a result of climate change may increase the likelihood and magnitude of damages that may be caused by fires. Residential and commercial development into the wildland-urban interface has also led to an increasing trend in the degree of destruction from wildfires.

Fires alleged to have been caused by our equipment potentially expose us to significant penalties and/or damage awards based on claims of strict liability, negligence, gross negligence, inverse condemnation, nuisance, trespass and others. Our equipment has been alleged to be involved in igniting wildfires although none have had a material adverse effect on our financial condition or results of operations.

For our electric generating facilities, operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs and potential litigation which may not be recovered from customers.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Additionally, during peak-load periods our electric and natural gas systems in Montana are constrained. These constraints limit our ability to transmit electric energy within Montana and access electric energy from outside the service area. Our electric transmission facilities are also interconnected with those of third parties, and thus operation of these facilities could be adversely affected by unexpected or uncontrollable events. Our natural gas system is also constrained, which limits our on-system deliverability and the ability to transport gas. We are similarly exposed to risk of interconnection with third-party pipelines and are dependent upon their operation to serve customers. These transmission constraints and events could result in failure to provide reliable service to customers due to the inability to deliver energy supply resources, or could result in significant cost increases due to the inability to access lower cost sources of energy supply.

Our electric and natural gas portfolios rely significantly on market purchases. This exposure adversely affects our ability to manage our operational requirements to reliably serve our customers, while exposing us to market volatility, which ultimately could adversely affect our results of operations and liquidity.

We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks including the ability to reliably serve customers and significant uncertainty in the cost of supply, which may not be recoverable. We rely upon a combination of base-load supply from our owned generation and market purchases to serve customers. The accredited capacity of our Montana portfolio of owned and long-term contracted electric generation resources covers 75 percent of our recent peak electric requirements, with remaining needs, including additional reserve margin, served through market purchases. In the past, Montana had been a net exporter of electric generation and we have relied upon Montana's excess generation for grid reliability and to physically serve customers. However, that situation in Montana has changed and we are predominantly a net importer, especially during peak demand. A significant number of base-load generation facilities, which may also serve to meet peak requirements, in the state and region have been retired or are scheduled to be retired in the next five to ten years. This includes Colstrip Units 1 and 2, representing 614 MWs of generation on a capacity basis, which ceased operations in January 2020. A decrease in the state and region's electric capacity, whether for operational reasons or litigation outcomes, may impair the reliability of the grid, particularly during peak demand periods. There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. There is also no assurance that the transmission capacity required to import market purchases will be available on transmission systems owned by us or by third parties. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. These conditions could result in an inability to physically deliver electricity to our customers. Losing electric service during extreme conditions carries significant consequences, as without our services our customers may be subjected to dire circumstances.

Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and the sharing component of the Montana PCCAM. During 2022, market prices for electricity and natural gas in peak periods were increasingly volatile, resulting in a significant under-collection of these costs impacting our results of operations and cash flows.

In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand.

Fluctuations in actual weather conditions, generation availability, transmission constraints, and generation reserve margins may all have an impact on market prices for energy and capacity and the electricity consumption of our customers on a given day. Extreme weather conditions may force us to purchase electricity in the short-term market on days when weather is unexpectedly severe, and the pricing for market energy may be significantly higher on such days than the cost of electricity in our existing generation and contracts. Unusually mild weather conditions could leave us with excess power which may be sold in the market at a loss if the market price is lower than the cost of electricity in our existing contracts.

Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that might be associated with climate change, could adversely affect our ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity.

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas. Our sensitivity to weather volatility is significant due to the absence of regulatory mechanisms, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs.

Severe weather impacts, including but not limited to, blizzards, thunderstorms, high winds, microbursts, floods, fires, tornadoes and snow or ice storms can disrupt energy generation, transmission and distribution. We derive a significant portion of our energy supply from hydroelectric facilities, and the availability of water can significantly affect operations. Higher temperatures may decrease the Montana snowpack and impact the timing of run-off and may require us to purchase replacement power. Dry conditions, which exist in the West and in our service territory, also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires that are alleged to have been caused by our system could expose us to substantial property damage and other claims. Any damage caused as a result of fires could negatively impact our financial condition, results of operations or cash flows.

The physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

Extreme weather conditions, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk we may be unable to reliably serve customers, causing brownouts and/or blackouts of our electric systems, and loss of gas supply. Risk of losing electricity or gas supply during extreme weather carries significant consequences as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

Our results of operations may be impacted by disruptions to fuel supply or the electric grid that are beyond our control.

We are exposed to risks related to performance of contractual obligations by our suppliers, which includes parties transporting natural gas. We are dependent on coal and natural gas for a significant portion of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short- and long-term contracts. We have certain supply and transportation contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply and deliver coal and natural gas to us. For instance, there currently is litigation pending relating to adequacy of certain permits for the Rosebud Mine in Montana, which supplies coal to Colstrip and contains significant quantities of coal. In order to operate the Colstrip facility through its currently identified retirement date of 2042, it will be necessary to identify and contract for coal supply subsequent to expiration of our current contract. Moreover, the suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply or transport coal and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather, availability of equipment and labor shortages. Failure or delay by our suppliers of coal and natural gas deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm, generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial position, results of operations and cash flows.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions or response to price increases. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing.

Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in their disposable income, and the use of distributed generation resources or other emerging technologies for electricity. Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production. Customer-owned generation itself reduces the amount of electricity purchased from utilities and may have the effect of inappropriately increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to collect distribution grid costs across all customers in a manner that reflects the benefit from their use. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the ongoing development of the Western Energy Imbalance Market, among other factors.

Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

Cyber and physical attacks, threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may affect our operations in unpredictable ways and could adversely affect our liquidity and results of operations. Failure to maintain the security of personally identifiable information could adversely affect us.

Business Operations - We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks, physical security breaches and other disruptive activities of individuals or groups, and theft of our critical infrastructure information. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. Cyber crime, which includes the use of malware, phishing attempts, computer viruses, and other means for disruption or unauthorized access has increased in frequency, scope, and potential impact in recent years. Our assets and the information technology systems on which they depend could be direct targets of, or indirectly affected by, cyber attacks and other disruptive activities, including those that impact third party facilities that are interconnected to us. Any significant interruption of these assets or systems could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential and other data could be compromised.

Security threats continue to evolve and transform. The risk of cyber-based attacks is heightened due to recent geopolitical events as well as employees working and accessing our technology infrastructure remotely. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, to confidential data, or to disrupt operations. With the continuing rise in ransomware and other cyber-based threats we have been analyzing our technology platforms and monitoring for signs of potential intrusions. We have also been reaching out to our vendors, suppliers and contractors requesting that they take appropriate measures. None of these attempts has individually or in the aggregate resulted in a security incident with a material impact on our financial condition or results of operations. However, despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact.

These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to the disruption of supplies and markets for electricity, natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity.

Personally Identifiable Information - Our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. Customers, shareholders, and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject us to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm our reputation.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We may have difficulty cost-effectively completing certain operations activities and construction projects due to inflationary pressures or if our third-party business partners are unable to deliver ordered supplies or complete contracted services timely, including workforce shortages or macro supply chain disruptions.

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases. Should these economic conditions and issues continue, we could have difficulty completing the operational activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations.

Failure to attract and retain an appropriately qualified workforce could affect our operations.

We require skilled labor to perform specialized utility functions. Turnover of key employees without appropriate replacements may lead to operating challenges and increased costs. Some of the challenges include lack of resources, loss of knowledge, and time required for replacement employees to develop necessary skills. Wage inflation nationally and increased competitive labor markets may make it difficult to attract employees. Failure to identify qualified replacement employees could result in decreased productivity and increased safety costs. If we are unable to attract and retain an appropriately qualified workforce, our operations could be negatively affected. We are also subject to multiple collective bargaining agreements. Future negotiation of these collective bargaining agreements could lead to work stoppages or other disruptions to our operations, which could adversely affect our financial condition and results of operations.

A pandemic or similar widespread public health concern could have a material negative impact on our business, financial condition and results of operations.

The actual or perceived effects of a disease outbreak, epidemic, pandemic or similar widespread public health concern, such as COVID-19, will likely negatively affect our business, financial condition and results of operations. The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets.

While the COVID-19 pandemic did not cause material disruptions to our operations, we could experience such disruptions in the future as a result of a pandemic (or a similar widespread public health concern) due to, among other things, quarantines, increased cyber risk due to employees working from home, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness, travel restrictions, or government mandates in connection with pandemics or disease outbreaks, our operations may be negatively affected.

Any such workforce implications and / or limitations or closures impact our ability to achieve our capital investment program and could have a material adverse impact on our ability to serve our customers and on our business, financial condition and results of operations.

Liquidity and Financial Risks

Our plans for future expansion through the acquisition of assets, capital improvements to existing assets, generation investments, and transmission grid expansion involve substantial risks.

Our business strategy includes significant investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to permitting, financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, these capital projects may require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support such projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital.

Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of our attention from daily operations to the integration of the acquisition, difficulties in assimilation and retention of employees, and securing adequate capital to support the transaction. The regulatory process in which rates are determined may not result in rates that produce full recovery of our investments, or a reasonable rate of return. Uncertainties also exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial synergies expected to result from an acquisition do not develop. The failure to successfully integrate future acquisitions that we may choose to undertake could have an adverse effect on our financial condition and results of operations.

Access to capital markets is critical to our operations and our capital structure. Increasing interest rates could have a material negative impact on our financial condition.

We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, U.S. and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms. We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time-to-time. For example, we have $145 million of 2% Montana secured debt maturing in 2023. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

We are subject to financial risks associated with the transition to a lower carbon economy.

The risks related to our transition to a lower-carbon economy, creates financial risk. Transition risks represent those risks related to the social and economic changes needed to shift toward a lower carbon future. These risks are often interconnected, representing policy and regulatory changes, technology and market risks, and risks to our reputation and financial performance.

Potential regulation associated with climate change legislation could pose financial risks to us. The U.S. is a party to the United Nations' "Paris Agreement" on climate change, and that agreement along with other potential legislation and regulation discussed above, could result in enforceable GHG emission reduction requirements that could lead to increased compliance costs for us. For example, the EPA has indicated that it is currently "evaluating additional opportunities" to reduce GHG emissions from existing power plants.

As we expand our energy generation asset mix, the ability to integrate renewable technologies into our operations and maintain reliability and affordability is a risk. The intermittency of renewables remains a critical challenge particularly as cost-efficient energy storage is still in development. Other technology risks include the need for significant upfront financial investments, lengthy development timelines, and the uncertainty of integration and scalability across our entire service territory.

To the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory costs, CO_2 taxes or imposed costs, we may be adversely impacted. There are also increasing risks for energy companies from shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change who may elect in the future to shift some or all of their investments into entities that emit lower levels of GHG emissions or into non-energy related sectors. Institutional investors and lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable investing and lending practices and some of them may elect not to provide funding for fossil fuel energy companies. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We may be subject to financial risks from private party litigation relating to GHG emissions. Defense costs associated with such litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. We continue to maintain our investment grade credit ratings. During a 2022 review process, Fitch Ratings downgraded our rating with a stable outlook. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to make up the difference. In addition, we are subject to price escalation risk with one of the largest QF contracts.

As part of a stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH through June 2029. This obligation is reflected in the electric QF liability, which reflects the unrecoverable costs associated with these specific QF contracts per the stipulation. The annual minimum energy requirement is achievable under normal operations of these facilities, including normal periods of planned and forced outages. However, to the extent the supplied power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to purchase the difference from other sources. The anticipated source for any shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted rates.

In addition, we are subject to price escalation risk with one of the largest contracts included in the electric QF liability due to variable contract terms. In recording the electric QF liability, we estimate an annual escalation rate over the remaining term of the contract (through June 2024). To the extent the annual escalation rate exceeds our estimate, our results of operations, cash flows and financial position could be adversely affected.

Changes in tax law may significantly impact our business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Similar to the Tax Cuts and Jobs Act, sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates and therefore may impact our results of operations, cash flows and financial position.

We are subject to counterparty credit risk.

We enter into transactions to buy and sell power, natural gas, and transmission service. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. Certain of these contracts may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in our credit ratings may lead to additional collateral posting requirements.

We are a participant in the energy markets, including the EIM, and engage in direct and indirect power purchase and sale transactions in connection with that participation. The EIM has collateral posting requirements based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that counterparties may owe each other in the EIM and any such credit losses could be socialized to all EIM participants, including us. A significant failure of a participant in the EIM to make payments when due on its obligations could have a ripple effect on various of our counterparties in the power and gas markets if those counterparties experience ancillary liquidity issues, and could generally result in a decline in the ability of our counterparties to perform on their obligations.

We also extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions, including unemployment rates, and industry conditions in which our commercial and industrial customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity.

Poor investment performance of plan assets of our defined benefit pension and postretirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our material properties include electric generating facilities, electric transmission and distribution lines, and natural gas production, transmission and distribution lines, which are described in Item 1 under Electric Operations and Natural Gas Operations. Substantially all of our Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. MINE SAFETY DISCLOSURES

None

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, which is traded under the ticker symbol NWE, is listed on the Nasdaq Stock Market. As of February 10, 2023, there were approximately 1,205 common stockholders of record.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following includes a discussion of our results of operations and cash flows for the year ended December 31, 2022 compared to the year ended December 31, 2021, on both a consolidated basis and on a segment basis. For a discussion of our financial results and cash flows for the year ended December 31, 2021 compared with the year ended December 31, 2020, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2021.

This discussion should be read in conjunction with our Consolidated Financial Statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our segments, see Note 20 - Segment and Related Information, to the Consolidated Financial Statements.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Utility Margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Utility Margin as Operating Revenues less fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion) as presented in our Consolidated Statements of Income. This measure differs from the GAAP definition of Gross Margin due to the exclusion of Operating and maintenance, Property and other taxes, and Depreciation and depletion expenses, which are presented separately in our Consolidated Statements of Income. The following discussion includes a reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure.

We believe that Utility Margin provides a useful measure for investors and other financial statement users to analyze our financial performance in that it excludes the effect on total revenues caused by volatility in energy costs and associated regulatory mechanisms. This information is intended to enhance an investor's overall understanding of results. Under our various state regulatory mechanisms, as detailed below, our supply costs are generally collected from customers. In addition, Utility Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates and other factors impact our results of operations. Our Utility Margin measure may not be comparable to that of other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 764,200 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2022, 2021 and 2020. Following is a discussion of our strategy and significant trends.

We work to deliver safe, reliable and innovative energy solutions that create value for customers, communities, employees and investors. We do this by providing low-cost and reliable service performed by highly-adaptable and skilled employees. We are focused on delivering long-term shareholder value through:

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in customer meters, distribution and substations that enables the use of proven new technologies.

- Investing in and integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.

- Continually improving our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings to continue to attract cost-effective capital for future investment.

We expect to pursue these investment opportunities and manage our business in a manner that allows us to be flexible in adjusting to changing economic conditions by adjusting the timing and scale of the projects.

In 2022, approximately 55 percent of our retail needs from our owned and long-term contracted resources originated from carbon-free resources, compared to approximately 39 percent for the total U.S. electric power industry. We are committed to providing customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. Towards this end, in 2022 we expanded and outlined our efforts towards a carbon-free future through our goal to achieve net zero carbon emissions by 2050. Our vision for the future builds on the progress we have made, including our hydroelectric system in Montana, which is 100 percent carbon free and is readily available capacity. For us, wind generation is a close second and continues to grow. While utility-scale solar energy has not been a significant portion of our energy mix to date, we recently entered into power purchase agreements with two solar projects totaling 160-megawatts that will begin delivering energy to our Montana customers in 2023. We expect solar to further evolve along with advances in energy storage. We are committed to working with our customers and communities to help them achieve their sustainability goals and add new technology on our system.

HOW WE PERFORMED IN 2022 COMPARED TO OUR 2021 RESULTS

	Year Ended December 31, 2022 vs. 2021		
	Income Before Income Taxes	Income Tax Benefit (Expense)	Net Income
	(in millions)		
Year ended December 31, 2021	$ 190.2	$ (3.4)	$ 186.8
Variance in revenue and fuel, purchased supply, and direct transmission expense[(1)] items impacting net income:			
Higher electric retail volumes	14.8	(3.7)	11.1
Interim rates (subject to refund)	9.5	(2.4)	7.1
Higher natural gas volumes	8.1	(2.1)	6.0
Lower electric transmission revenue	(4.8)	1.2	(3.6)
A less favorable electric QF liability adjustment	(2.4)	0.6	(1.8)
Higher non-recoverable Montana electric supply costs	(1.8)	0.5	(1.3)
Variance in expense items[(2)] impacting net income:			
Higher operating, maintenance, and administrative expenses	(10.9)	2.8	(8.1)
Higher depreciation expense	(7.5)	1.9	(5.6)
Higher interest expense	(6.4)	1.6	(4.8)
Higher property tax expenses	(5.5)	1.5	(4.0)
Other	(0.9)	2.1	1.2
Year ended December 31, 2022	$ 182.4	$ 0.6	$ 183.0
Change in Net Income			$ (3.8)

(1) Exclusive of depreciation and depletion shown separately below
(2) Excluding fuel, purchased supply, and direct transmission expense

Consolidated net income in 2022 was $183.0 million as compared with $186.8 million in 2021. This decrease was primarily due to higher operating costs, higher depreciation expense, higher interest expense, higher property taxes that were not offset in revenues, lower transmission revenues, and a less favorable QF liability adjustment as compared to the prior year, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth and higher Montana interim rate revenue associated with our ongoing rate review, which are subject to refund.

SIGNIFICANT TRENDS AND REGULATION

Regulatory Update

Rate Review Filings – Rate reviews are necessary to recover the cost of providing safe, reliable service, while contributing to earnings growth and achieving our financial objectives. We regularly review the need for electric and natural gas rate relief in each state in which we provide service. On August 8, 2022, we filed a Montana electric and natural gas rate review filing (2021 test year) under Docket 2022.07.78. A summary of our requests within this rate review is below:

Montana Rate Review ($ in millions)

	Electric	Natural Gas
Proposed ROE	10.60%	10.60%
Proposed Equity Ratio	48.02%	48.02%
Forecasted 2022 Rate Base	$2,790	$575
Net Rate Base Increase	$453	$143

Requested Revenue Increase (in millions)

	Electric	Natural Gas
Base Rates	$91.8	$20.2
Power Cost & Credit Mechanism (PCCAM)[1]	$68.1	n/a
Property Tax (tracker true-up)[1]	$11.1	$2.8
Total	$171.0	$23.0

(1) These items are flow-through costs, which represent approximately 42% of the requested electric and natural gas revenue increase.

Within this rate review filing we requested an increase to the PCCAM base rate (PCCAM Base) of $68.1 million as well as structural revisions to the PCCAM mechanism to provide customers with prices that better reflect the cost of services received. We also proposed to implement a revised electric only pilot for the FCRM beginning July 1, 2023, or alternatively to terminate the FCRM. Our rate review filing also includes proposals for more timely cost recovery beyond the test period, including critical reliability resources, such as the Yellowstone County Generating Station, our Enhanced Wildfire Mitigation plan, and business technology maintenance costs.

Interim Rates - On September 28, 2022, the MPSC approved the recommendations of the MPSC Staff for interim rates, subject to refund, which increased base electric rates $29.4 million, PCCAM Base rates $61.1 million, and base natural gas rates $1.7 million, effective October 1, 2022.

Key dates in the procedural schedule are expected to be as follows:

- NorthWestern rebuttal testimony and cross-intervenor testimony - March 6, 2023
- Hearing commences - April 11, 2023

Montana PCCAM - The Montana PCCAM Base of $138.7 million, approved in 2019, no longer reflects an accurate current forecast of our normal fuel and power costs. The MPSC's September 28, 2022 decision approving interim rates, which are subject to refund, in our rate review included an increase to the PCCAM Base of $61.1 million, on an interim basis, effective October 1, 2022. As of December 31, 2022, we have under-collected our total Montana electric supply costs for the current July 2022 through June 2023 PCCAM year by approximately $44.8 million. Absent the interim rate PCCAM Base increase, as of December 31, 2022, our under-collected position would have been approximately $55.9 million. Under-collections are not reflected in customer bills and are not recovered until the subsequent power cost adjustment year, adversely affecting our cash flows and liquidity.

Under the PCCAM, under and over-collection of non-qualifying facility related net costs are allocated 90% to Montana customers and 10% to shareholders. For the twelve months ended December 31, 2022, we deferred $64.8 million of costs to be collected from customers (90% of the costs above base) and recorded a reduction in pre-tax earnings of $7.2 million (10% of the variance). For the twelve months ended December 31, 2021, we deferred $48.7 million of costs for future collection from customers and recorded a reduction in pre-tax earnings of $5.4 million.

Our electric supply from owned and long-term contracted resources is not adequate to meet our peak-demand needs. Because of this, the volatility of market prices for energy on peak-demand days, even if only for a few days in duration, exposes us to potentially significant market purchases that could negatively impact our results of operations and cash flows. See the Electric Resource Planning - Montana section below for how we are working to address this market exposure.

Holding Company Filings - On June 1, 2022, we filed a legal corporate restructuring application (Restructuring Plan) with the state commissions in Montana, South Dakota and Nebraska and the FERC. Currently, our utility businesses are held in the same legal entity. Under the proposed Restructuring Plan, we would legally separate our Montana public utility business from our South Dakota and Nebraska public utility business and establish a holding company to hold the ownership interests of all of the subsidiaries. The purpose of the reorganization is to integrate our organizational structure to be more transparent and in line with the public utility industry.

The Restructuring Plan does not propose and we do not expect any procedural or substantive change in how the state public utility commissions regulate those services. Implementation of the Restructuring Plan is subject to receipt of all regulatory approvals. On July 26, 2022, the NPSC approved our Restructuring Plan application. On August 3, 2022, the SDPUC approved the application. On November 29, 2022, the FERC approved the application. NorthWestern reached settlement terms with the intervenors in the Montana proceeding, and the MPSC is reviewing those terms.

Electric Resource Planning - Montana

Yellowstone County 175 MW plant - Construction at the site began in April 2022 with a current schedule that is expected to allow the plant to serve our Montana customers during 2024 with total construction costs of approximately $275.0 million ($154.9 million incurred through December 31, 2022).

On October 21, 2021, the Montana Environmental Information Center (MEIC) and the Sierra Club filed a lawsuit in Montana State Court, against the Montana Department of Environmental Quality (MDEQ) and us, alleging that the environmental analysis conducted prior to issuance of the Yellowstone County Generating Station's air quality permit was inadequate. The Montana District Court judge held oral argument on June 20, 2022. We expect a decision in 2023. This lawsuit, as well as additional legal challenges related to the Yellowstone County Generating Station, could delay the project timing. Construction is ongoing while we are awaiting this decision.

Acquisition of Colstrip Interest - On January 16, 2023, we entered into a definitive agreement (the Avista Agreement) with Avista Corporation (Avista) to acquire Avista's 15 percent interest in each of Units 3 and 4 at the Colstrip Generating Station, a coal-fired, base-load electric generation facility located in Colstrip, Montana. The Avista Agreement provides that the purchase price will be $0 and that we will acquire Avista's interest effective December 31, 2025, subject to the satisfaction of the closing conditions contained within the Avista Agreement. Under the terms of this Avista Agreement, we will be responsible for operating costs starting on January 1, 2026; while Avista will retain responsibility for its pre-closing share of environmental and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommission and demolition costs associated with the existing facilities that comprise Avista's interest.

The Avista Agreement contains customary representations and warranties, covenants, and indemnification obligations, and the Avista Agreement is subject to customary conditions and approvals, including approval from the FERC. Closing also is conditioned on our ability to enter into a new coal supply agreement for Colstrip by December 31, 2024. Such coal supply agreement must provide a sufficient amount of coal to Colstrip to permit the generation of electric power by the maximum permitted capacity of the interest in Colstrip then held by us during the period from January 1, 2026 through, December 31, 2030.

Either party may terminate the Avista Agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing. The Avista Agreement may be subject to the exercise by other Colstrip owners of a right of first refusal set forth in the O&O Agreement. Should any other owners exercise such rights, we intend to exercise our right of first refusal under the O&O Agreement to the fullest extent permitted, and Avista has agreed that it will not exercise its right of first refusal.

The acquisition of an additional interest under this Avista Agreement in 2026 will provide capacity to help us meet our obligation to provide reliable and cost effective power to our customers in Montana, while allowing opportunity for us to identify and plan for newer technologies to provide reliable, affordable and carbon free power through our IRP process.

Future Integrated Resource Planning - Resource adequacy in the Western third of the U.S. has been declining with the retirement of thermal power plants. Our owned and long-term contracted resources are inadequate to supply the necessary capacity we require to meet our peak-demand loads, which exposes us to large quantities of market purchases at typically high and volatile energy prices. To comply with regulatory resource planning requirements, we expect to submit an integrated resource plan to the MPSC by the end of March 2023.

We remain concerned regarding an overall lack of capacity in the West and our owned and long-term contracted capacity deficit to meet peak-demand loads. The construction of the Yellowstone County Generating Station and acquisition of Avista's Colstrip Units 3 and 4 interests, as discussed above, will reduce our exposure to market purchases at typically high and volatile energy prices.

Electric Resource Supply - South Dakota

Our new Bob Glanzer Generating Station was operational as of May 27, 2022. The 58 MW natural gas plant is located in Huron, South Dakota.

Our electric supply resource plans for South Dakota continue to identify portfolio requirements including potential investments resulting from a completed competitive solicitation process. We filed an updated integrated resource plan on September 6, 2022, which is consistent with the prior plan laying out a retire and replace generation asset strategy. A decision on what process to use, and what type of generation technology to add, is expected to be made in the first half of 2023.

Supply Chain and Inflation Challenges

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases. Should challenges with product and services availability and price inflation continue, we could have difficulty timely completing the operations activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations.

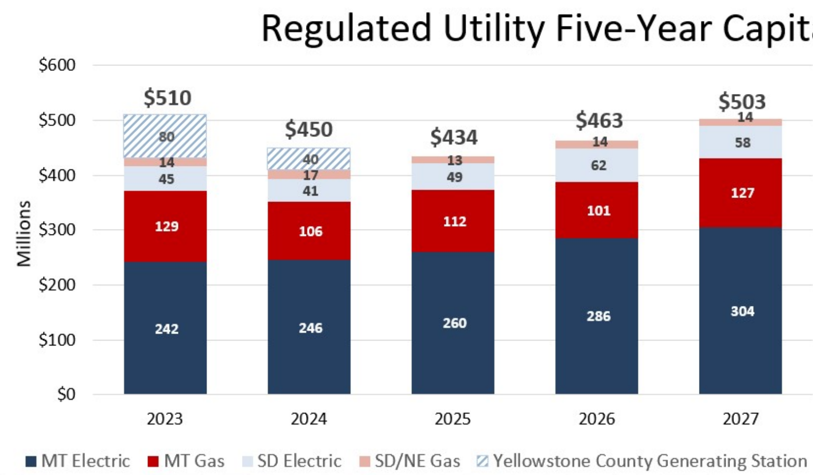
Enhanced Wildfire Mitigation

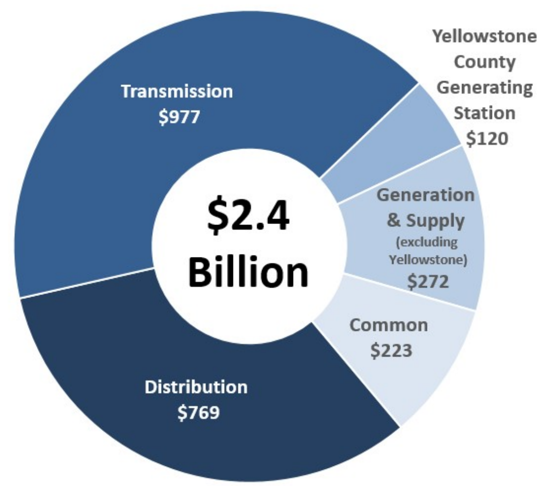
With changing weather conditions which include more significant wind events, drought conditions, and warmer air temperatures, we do not consider the fire season specific to a time of year, but rather a condition that may exist at any time of year. Each year's weather conditions impact these situations differently: early season rains encourage plant growth which fuels fires later in the growing season, and winters with little snow leave dry plant material available for late season fires. The threat is not only in forested areas, where insect infestations and resulting tree death has been severe, but across the entire system including rural areas where grassland fires could be ignited, along with urban areas where extreme weather conditions pose a great risk to heavily populated areas.

Recognizing the risk of significant wildfires in Montana, we continue to proactively seek to mitigate wildfire risk. We have developed an Enhanced Wildfire Mitigation Plan addressing five key areas: situational awareness, operational practices, system preparedness, vegetation management, and public communications and outreach. This plan builds upon several key initiatives that were initiated and executed over the past decade including nearly $80 million spent on vegetation management and hazard tree removal programs and our growing annual investment to harden our transmission and distribution system infrastructure. Because of ever-increasing wildfire risk, our plan includes greater focus on situational awareness to monitor changing environmental conditions, operational practices that are more reactive to changing conditions, increased frequency of patrol and repairs, and more robust system hardening programs that target higher risk segments in our transmission and distribution systems. We included a request for expected costs associated with the mitigation plan in our 2022 Montana rate review.

SIGNIFICANT INFRASTRUCTURE INVESTMENTS AND INITIATIVES

Our estimated capital expenditures for the next five years, including our electric and natural gas transmission and distribution and electric generation infrastructure investment plan, are as follows (in millions):





$ Millions	2023	2024	2025	2026	2027
Electric	367	327	309	348	363
Natural Gas	143	123	125	115	140
Total Capital Forecast	**$510**	**450**	**$434**	**$463**	**$503**

Electric Supply Resource Plans - Our energy resource plans identify portfolio resource requirements including potential investments. Included within our projections above is approximately $120.0 million of capital to complete construction of the 175 MW Yellowstone County Generating Station to be on line in 2024.

Distribution and Transmission Modernization and Maintenance - The primary goals of our infrastructure investments are to reverse the trend in aging infrastructure, maintain reliability, proactively manage safety, build capacity into the system, and prepare our network for the adoption of new technologies. We are taking a proactive and pragmatic approach to replacing these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. Beginning in 2021, and continuing through 2025, we expect to install automated metering infrastructure in Montana at a total cost of approximately $112.0 million, of which, $66.1 million remains and is reflected in the five year capital forecast above.

RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of utility margin by segment.

Factors Affecting Results of Operations

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted by customer growth and usage, the latter of which is primarily affected by weather and the impact of energy efficiency initiatives and investment. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

Fuel, purchased supply and direct transmission expenses are costs directly associated with the generation and procurement of electricity and natural gas. These costs are generally collected in rates from customers and may fluctuate substantially with market prices and customer usage.

Operating and maintenance expenses are costs associated with the ongoing operation of our vertically-integrated utility facilities which provide electric and natural gas utility products and services to our customers. Among the most significant of these costs are those associated with direct labor and supervision, repair and maintenance expenses, and contract services. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in volumes.

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2022 Compared with Year Ended December 31, 2021

Consolidated net income in 2022 was $183.0 million as compared with $186.8 million in 2021, a decrease of $3.8 million. As described in more detail below, this decrease was primarily due to higher operating costs, higher depreciation expense, higher interest expense, higher property taxes that were not offset in revenues, lower transmission revenues due to the prior year recognition of deferred transmission revenue and lower prices, and a less favorable QF liability adjustment as compared to the prior year, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth and higher Montana electric and natural gas interim rate revenue, which is subject to refund.

Consolidated gross margin in 2022 was $376.9 million as compared with $377.7 million in 2021, a decrease of $0.8 million or 0.2 percent. This decrease was primarily due to lower transmission revenues due to the prior year recognition of deferred transmission revenue and lower prices, a less favorable QF liability adjustment as compared to the prior year, higher operating and maintenance expense, and higher depreciation and depletion, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth and the interim rate increase, which is subject to refund.

	Electric		Natural Gas		Total	
	2022	2021	2022	2021	2022	2021
			(in millions)			
Reconciliation of gross margin to utility margin:						
Operating Revenues	$1,106.5	$1,052.2	$ 371.3	$ 320.1	$1,477.8	$1,372.3
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	324.4	294.8	167.6	130.7	492.0	425.5
Less: Operating and maintenance	167.8	156.4	53.6	51.9	221.4	208.3
Less: Property and other taxes	149.8	134.9	42.7	38.5	192.5	173.4
Less: Depreciation and depletion	162.4	154.6	32.6	32.8	195.0	187.4
Gross Margin	**302.1**	**311.5**	**74.8**	**66.2**	**376.9**	**377.7**
Operating and maintenance	167.8	156.4	53.6	51.9	221.4	208.3
Property and other taxes	149.8	134.9	42.7	38.5	192.5	173.4
Depreciation and depletion	162.4	154.6	32.6	32.8	195.0	187.4
Utility Margin(1)	**$ 782.1**	**$ 757.4**	**$ 203.7**	**$ 189.4**	**$ 985.8**	**$ 946.8**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Year Ended December 31,			
	2022	2021	Change	% Change
		(in millions)		
Utility Margin				
Electric	$ 782.1	$ 757.4	$ 24.7	3.3 %
Natural Gas	203.7	189.4	14.3	7.6
Total Utility Margin(1)	**$ 985.8**	**$ 946.8**	**$ 39.0**	**4.1 %**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated utility margin in 2022 was $985.8 million as compared with $946.8 million in 2021, an increase of $39.0 million, or 4.1 percent.

Primary components of the change in utility margin include the following (in millions):

		Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income		
Higher electric retail volumes	$	14.8
Montana interim rates (subject to refund)		9.5
Higher natural gas retail volumes		8.1
Lower transmission revenue due to lower transmission rates and the prior year recognition of approximately $4.7 million of deferred interim rates, partly offset by higher demand		(4.8)
A less favorable electric QF liability adjustment		(2.4)
Higher non-recoverable Montana electric supply costs		(1.8)
Reduction of rates from the step down of our Montana gas production assets		(0.8)
Other		2.3
Change in Utility Margin Impacting Net Income		**24.9**
Utility Margin Items Offset Within Net Income		
Higher property taxes recovered in revenue, offset in property tax expense		13.3
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		2.5
Higher gas production taxes recovered in revenue, offset in property and other taxes		0.3
Lower revenue from higher production tax credits, offset in income tax expense		(2.0)
Change in Items Offset Within Net Income		**14.1**
Increase in Consolidated Utility Margin[1]	**$**	**39.0**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Higher electric retail volumes were driven by overall favorable weather in all jurisdictions and customer growth. Higher natural gas retail volumes were driven by favorable weather in all jurisdictions and customer growth. Interim rates in our Montana rate review were effective October 1, 2022, and are subject to refund pending an outcome in the proceeding.

The less favorable adjustment to our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflects a $5.1 million gain in 2022, as compared with a $7.5 million gain for the same period in 2021, due to the combination of:

- A $1.8 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $2.6 million favorable reduction in costs in the prior period;
- A favorable adjustment, decreasing the QF liability by $3.3 million, reflecting annual actual contract price escalation for the 2022-2023 contract year, which was less than previously estimated, partly offset by an increase in estimated contract prices for the 2023-2024 contract year, which is the last year of the contract that contains variable pricing terms. See Critical Accounting Policies and Estimates below for further information regarding our process of estimating the contract price for the 2023-2024 contract year. This is compared to an unfavorable adjustment of $2.1 million in the prior year due to higher actual price escalation; and
- A favorable adjustment in the prior year, decreasing the QF liability by approximately $7.0 million, associated with a one-time clarification in contract term.

	Year Ended December 31,			
	2022	2021	Change	% Change
	(in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 221.4	$ 208.3	$ 13.1	6.3 %
Administrative and general	113.8	101.9	11.9	11.7
Property and other taxes	192.5	173.4	19.1	11.0
Depreciation and depletion	195.0	187.5	7.5	4.0
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 722.7**	**$ 671.1**	**$ 51.6**	**7.7 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $722.7 million in 2022, as compared with $671.1 million in 2021. Primary components of the change include the following (in millions):

	Operating Expenses 2022 vs. 2021
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Higher depreciation expense due to plant additions	$ 7.5
Higher property tax expense due to an increase in estimated state and local taxes	5.5
Higher insurance expense	2.2
Increase in uncollectible accounts due to the prior year collection of previously written off balances	2.0
Higher cost of materials	1.9
Higher technology implementation and maintenance expenses	1.8
Higher travel expenses	1.6
Higher fleet fuel costs	1.6
Higher advertising expenses	1.0
Higher expenses at our electric generation facilities	0.4
Lower labor and benefits due to higher capitalization of labor and benefits costs and lower pension costs, partly offset by higher labor costs(1)	(2.1)
Prior year write off of preliminary construction costs	(1.6)
Other	2.1
Change in Items Impacting Net Income	**23.9**
Operating Expenses Offset Within Net Income	
Higher property and other taxes recovered in trackers, offset in revenue	13.6
Higher pension and other postretirement benefits, offset in other income(1)	12.8
Higher operating expenses recovered in trackers, offset in revenue	2.5
Lower non-employee directors deferred compensation, offset in other income	(1.2)
Change in Items Offset Within Net Income	**27.7**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 51.6**

(1) In order to present the total change in labor and benefits, we have included the change in the non-service cost component of our pension and other postretirement benefits, which is recorded within other income on our Condensed Consolidated Statements of Income. This change is offset within this table as it does not affect our operating expenses.

Consolidated operating income in 2022 was $263.1 million as compared with $275.7 million in 2021. This decrease was primarily due to lower transmission revenues due to the prior year recognition of deferred transmission revenue and lower prices, a less favorable QF liability adjustment as compared to the prior year, higher operating and maintenance expense, higher administrative and general expense, higher property tax expense, and higher depreciation and depletion, partly offset by higher electric and natural gas retail volumes due to favorable weather and customer growth, and the interim rate increase, which is subject to refund pending an outcome in the proceeding.

Consolidated interest expense in 2022 was $100.1 million, as compared with $93.7 million in 2021. This increase was primarily due to higher interest rates on borrowings under our revolving credit facilities partly offset by higher capitalization of AFUDC.

Consolidated other income in 2022 was $19.4 million, as compared with $8.3 million in 2021. This increase was primarily due to a decrease in the non-service cost component of pension expense and higher capitalization of AFUDC, partly offset by a $2.5 million CREP penalty, which relates to litigation we have been involved in associated with our past progress towards meeting obligations to acquire renewable energy projects as mandated by the recently repealed Montana CREP requirement, and a decrease in the value of deferred shares held in trust for non-employee directors deferred compensation.

Consolidated income tax benefit in 2022 was $0.6 million, as compared to an income tax expense of $3.4 million in 2021. Our effective tax rate for the twelve months ended December 31, 2022 was (0.3) percent as compared with 1.8 percent for the same period of 2021.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

	Year Ended December 31,			
	2022		2021	
Income Before Income Taxes	$ 182.4		$ 190.3	
Income tax calculated at federal statutory rate	38.3	21.0 %	40.0	21.0 %
Permanent or flow through adjustments:				
State income taxes, net of federal provisions	0.6	0.3	0.4	0.1
Flow-through repairs deductions	(22.7)	(12.4)	(21.9)	(11.5)
Production tax credits	(13.2)	(7.2)	(11.5)	(6.1)
Amortization of excess deferred income taxes	(1.7)	(0.9)	(0.6)	(0.3)
Prior year permanent return to accrual adjustments	(1.4)	(0.8)	—	—
Plant and depreciation of flow through items	(0.2)	(0.1)	(0.9)	(0.6)
Other, net	(0.3)	(0.2)	(2.1)	(0.8)
	(38.9)	(21.3)	(36.6)	(19.2)
Income Tax (Benefit) Expense	$ (0.6)	(0.3)%	$ 3.4	1.8 %

Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

ELECTRIC OPERATIONS

We have various classifications of electric revenues, defined as follows:

- Retail: Sales of electricity to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for electric supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in fuel, purchased supply and direct transmission expense and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Transmission: Reflects transmission revenues regulated by the FERC.
- Wholesale and other are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expense.

Year Ended December 31, 2022 Compared with Year Ended December 31, 2021

	Revenues		Change		MWHs		Avg. Customer Counts	
	2022	2021	$	%	2022	2021	2022	2021
	(in thousands)							
Montana	$ 357,384	$ 334,581	$ 22,803	6.8 %	2,868	2,729	316,968	311,922
South Dakota	69,809	65,429	4,380	6.7	596	571	51,069	50,805
Residential	**427,193**	**400,010**	**27,183**	**6.8**	**3,464**	**3,300**	**368,037**	**362,727**
Montana	368,634	356,669	11,965	3.4	3,237	3,176	73,093	71,605
South Dakota	108,202	102,475	5,727	5.6	1,114	1,092	12,897	12,795
Commercial	**476,836**	**459,144**	**17,692**	**3.9**	**4,351**	**4,268**	**85,990**	**84,400**
Industrial	39,773	37,866	1,907	5.0	2,590	2,448	76	77
Other	31,007	32,084	(1,077)	(3.4)	161	175	6,406	6,333
Total Retail Electric	**$ 974,809**	**$ 929,104**	**$ 45,705**	**4.9 %**	**10,566**	**10,191**	**460,509**	**453,537**
Regulatory amortization	46,382	34,395	11,987	34.9				
Transmission	77,791	82,628	(4,837)	(5.9)				
Wholesale and Other	7,583	6,055	1,528	25.2				
Total Revenues	**$1,106,565**	**$1,052,182**	**$ 54,383**	**5.2 %**				
Fuel, purchased supply and direct transmission expense(1)	**324,434**	**294,820**	**29,614**	**10.0**				
Utility Margin(2)	**$ 782,131**	**$ 757,362**	**$ 24,769**	**3.3 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana	602	635	445	5% cooler	35% warmer
South Dakota	953	1,034	752	8% cooler	27% warmer

	Heating Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana(1)	8,004	7,217	7,493	11% colder	7% colder
South Dakota	7,687	6,758	7,694	14% colder	remained flat

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in electric utility margin for the years ended December 31, 2022 and 2021 (in millions):

		Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income		
Higher retail volumes	$	14.8
Montana interim rates (subject to refund)		8.7
Lower transmission revenue due to lower transmission rates and the prior year recognition of approximately $4.7 million of deferred interim rates, partly offset by higher demand		(4.8)
A less favorable QF liability adjustment		(2.4)
Higher non-recoverable Montana electric supply costs		(1.8)
Other		0.2
Change in Utility Margin Items Impacting Net Income		**14.7**
Utility Margin Items Offset Within Net Income		
Higher property taxes recovered in revenue, offset in property tax expense		9.7
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		2.3
Lower revenue from higher production tax credits, offset in income tax expense		(2.0)
Change in Items Offset Within Net Income		**10.0**
Increase in Utility Margin[1]	**$**	**24.7**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Higher retail volumes were driven by overall favorable weather in all jurisdictions and customer growth.

The less favorable adjustment to our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflects a $5.1 million gain in 2022, as compared with a $7.5 million gain for the same period in 2021, due to the combination of:

- A $1.8 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $2.6 million favorable reduction in costs in the prior period;
- A favorable adjustment, decreasing the QF liability by $3.3 million, reflecting annual actual contract price escalation for the 2022-2023 contract year, which was less than previously estimated, partly offset by an increase in estimated contract prices for the 2023-2024 contract year, which is the last year of the contract that contains variable pricing terms. See Critical Accounting Policies and Estimates below for further information regarding our process of estimating the contract price for the 2023-2024 contract year. This is compared to an unfavorable adjustment of $2.1 million in the prior year due to higher actual price escalation; and
- A favorable adjustment in the prior year, decreasing the QF liability by approximately $7.0 million, associated with a one-time clarification in contract term.

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on utility margin. Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

NATURAL GAS OPERATIONS

We have various classifications of natural gas revenues, defined as follows:

- Retail: Sales of natural gas to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for natural gas supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in fuel, purchased supply and direct transmission expenses and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Wholesale: Primarily represents transportation and storage for others.

Year Ended December 31, 2022 Compared with Year Ended December 31, 2021

	Revenues		Change		Dekatherms		Avg. Customer Counts	
	2022	2021	$	%	2022	2021	2022	2021
	(in thousands)							
Montana	$ 152,343	$ 126,043	26,300	20.9 %	15,319	13,885	181,879	179,637
South Dakota	39,178	26,596	12,582	47.3	3,280	2,834	41,524	41,079
Nebraska	35,756	20,964	14,792	70.6	2,558	2,480	37,693	37,603
Residential	**227,277**	**173,603**	**53,674**	**30.9**	**21,157**	**19,199**	**261,096**	**258,319**
Montana	79,274	64,681	14,593	22.6	8,329	7,446	25,319	24,927
South Dakota	28,487	19,131	9,356	48.9	2,981	2,744	7,058	6,896
Nebraska	22,071	11,371	10,700	94.1	1,846	1,755	5,003	4,963
Commercial	**129,832**	**95,183**	**34,649**	**36.4**	**13,156**	**11,945**	**37,380**	**36,786**
Industrial	1,520	1,134	386	34.0	163	135	232	229
Other	1,932	1,417	515	36.3	232	187	178	166
Total Retail Gas	**$ 360,561**	**$ 271,337**	**$ 89,224**	**32.9 %**	**34,708**	**31,466**	**298,886**	**295,500**
Regulatory amortization	(27,964)	12,048	(40,012)	(332.1)				
Wholesale and other	38,675	36,749	1,926	5.2				
Total Revenues	**$ 371,272**	**$ 320,134**	**$ 51,138**	**16.0 %**				
Fuel, purchased supply and direct transmission expense[(1)]	**167,577**	**130,728**	**36,849**	**28.2**				
Utility Margin[(2)]	**$ 203,695**	**$ 189,406**	**$ 14,289**	**7.5 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Heating Degree Days			2022 as compared with:	
	2022	2021	Historic Average	2021	Historic Average
Montana[(1)]	8,194	7,390	7,706	11% colder	6% colder
South Dakota	7,687	6,758	7,694	14% colder	remained flat
Nebraska	5,767	5,632	6,087	2% colder	5% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in natural gas utility margin for the years ended December 31, 2022 and 2021 (in millions):

		Utility Margin 2022 vs. 2021
Utility Margin Items Impacting Net Income		
Higher retail volumes	$	8.1
Montana interim rates (subject to refund)		0.8
Reduction of rates from the step down of our Montana gas production assets		(0.8)
Other		2.1
Change in Utility Margin Impacting Net Income		**10.2**
Utility Margin Items Offset Within Net Income		
Higher property taxes recovered in revenue, offset in property tax expense		3.6
Higher gas production taxes recovered in revenue, offset in property and other taxes		0.3
Higher operating expenses recovered in revenue, offset in operating and maintenance expense		0.2
Change in Items Offset Within Net Income		**4.1**
Increase in Utility Margin(1)	**$**	**14.3**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Higher retail volumes were driven by favorable weather in all jurisdictions and customer growth.

Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future utility rate increases should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures. We plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases, and expect to continue targeting a long-term dividend payout ratio of 60 - 70 percent of earnings per share; however, there can be no assurance that we will be able to meet these targets.

As of December 31, 2022, our total net liquidity was approximately $108.5 million, including $8.5 million of cash and $100.0 million of revolving credit facility availability with no letters of credit outstanding.

Cash Flows

The following table summarizes our consolidated cash flows (in millions):

	Year Ended December 31,	
	2022	2021
Operating Activities		
Net income	$ 183.0	$ 186.8
Non-cash adjustments to net income	183.1	187.5
Changes in working capital	(37.0)	(120.6)
Other noncurrent assets and liabilities	(21.9)	(33.7)
Cash Provided by Operating Activities	**307.2**	**220.0**
Investing Activities		
Property, plant and equipment additions	(515.1)	(434.3)
Investment in equity securities	(1.7)	(1.5)
Cash Used in Investing Activities	**(516.8)**	**(435.8)**
Financing Activities		
Proceeds from issuance of common stock, net	277.0	196.2
Issuance of long-term debt	—	99.9
Repayments of short-term borrowings	—	(100.0)
Dividends on common stock	(140.1)	(128.5)
Line of credit borrowings, net	77.0	151.0
Financing costs	(1.2)	(0.9)
Other	0.6	(0.2)
Cash Provided by Financing Activities	**213.3**	**217.5**
Net Increase in Cash, Cash Equivalents, and Restricted Cash	**$ 3.7**	**$ 1.7**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 18.8	$ 17.1
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 22.5**	**$ 18.8**

Operating Activities

As of December 31, 2022, cash, cash equivalents, and restricted cash were $22.5 million as compared with $18.8 million as of December 31, 2021. Cash provided by operating activities totaled $307.2 million for the year ended December 31, 2022 as compared with $220.0 million for the year ended December 31, 2021. As shown in the table below, this increase in operating cash flows is primarily due to a $78.0 million improvement in net cash outflows for uncollected energy supply costs during the year ended December 31, 2022, compared to the year ended December 31, 2021. The 2021 period includes costs incurred during a February 2021 prolonged cold weather event and a significant under-collected position of Montana's PCCAM for the July 2020 - June 2021 period. While we have various regulatory mechanisms that supported our recovery of much of the 2021 under-collected position during 2022, higher overall market prices during 2022 have resulted in new under-collected energy supply costs that more than offset the recovery of the prior year balances. In addition, we issued a refund of approximately $20.5 million to our FERC regulated wholesale customers and approximately $6.1 million to our Montana electric retail customers in the prior period.

Net under-collected supply costs (in millions)

	Beginning of year	End of year	Net cash outflows
2021	$ 4.8	$ 99.1	$ (94.3)
2022	$ 99.1	$ 115.4	$ (16.3)
		Improvement in annual net cash outflows	$ 78.0

As of December 31, 2022, our uncollected energy supply cost balance includes $41.4 million related to the July 2021 - June 2022 PCCAM period, which has been included in customer rates for recovery beginning October 1, 2022. The balance also includes an additional $44.8 million under-collection related to the PCCAM period that began on July 1, 2022. As part of our Montana general rate review we have requested an increase to the PCCAM base to more accurately reflect the current higher overall market energy prices. On September 28, 2022, the MPSC approved our request for interim rates, which are subject to refund, including a $61.1 million increase to the PCCAM Base, which became effective in customer rates on October 1, 2022. Our under-collected position improved $12.1 million due to the interim rate approved PCCAM Base. However, even with this PCCAM Base increase in the fourth quarter of 2022 we under-collected supply costs from customers.

Assuming a favorable final outcome on our Montana rate review and PCCAM mechanism requests we anticipate continued improvements in our cash flows from operations. However, unfavorable results in our Montana rate review, and continued higher overall market prices, which could be further exacerbated by extreme weather events, could create additional costs with deferred recovery that would offset these anticipated cash flow improvements.

Investing Activities

Cash used in investing activities totaled $516.8 million during the year ended December 31, 2022, as compared with $435.8 million during 2021. Plant additions during 2022 include capital maintenance additions of approximately $295.4 million and capacity related capital expenditures of approximately $219.7 million. Plant additions during 2021 included capital maintenance additions of approximately $314.1 million and capacity related capital expenditures of approximately $120.2 million. As discussed above in the “Significant Infrastructure Investments and Initiatives” section, our capital expenditures are forecasted to be $510 million in 2023.

Financing Activities

Cash provided by financing activities totaled $213.3 million during the year ended December 31, 2022 as compared with $217.5 million during the year ended December 31, 2021. During the year ended December 31, 2022, cash provided by financing activities reflects proceeds received from the issuance of common stock of $277.0 million and net issuances under our revolving lines of credit of $77.0 million, offset in part by payment of dividends of $140.1 million. During the year ended December 31, 2021, cash provided by financing activities reflects proceeds received from the issuance of common stock of $196.2 million, net proceeds from the issuance of debt of $99.9 million, and net issuances under our revolving lines of credit of $151.0 million, offset in part by payment of dividends of $128.5 million and repayments of our short-term borrowings of $100.0 million.

Cash Requirements and Capital Resources

We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future rate increases should be sufficient to satisfy our material cash requirements over the short-term and the long-term. As a rate-regulated utility our customer rates are generally structured to recover expected operating costs, with an opportunity to earn a return on our invested capital. This structure supports recovery for many of our operating expenses, although there are situations where the timing of our cash outlays results in increased working capital requirements. Due to the seasonality of our utility business, our short-term working capital requirements typically peak during the coldest winter months and warmest summer months when we cover the lag between when purchasing energy supplies and when customers pay for these costs. Our credit facilities may also be utilized for funding cash requirements during seasonally active construction periods, with peak activity during warmer months. Our cash requirements also include a variety of contractual obligations as outlined below in the "Contractual Obligations and Other Commitments" section.

Our material cash requirements are also related to investment in our business through our capital expenditure program, which is discussed above in the "Significant Infrastructure Investments and Initiatives" section. Our capital expenditures are forecasted to increase to $510 million in 2023, $450 million in 2024, and $434 million in 2025. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt and equity issuances and future rate increases. The actual amount of capital expenditures is subject to certain factors including the impact that a material change in operations, available financing, supply chain issues, or inflation could impact our current liquidity and ability to fund capital resource requirements. Events such as these could cause us to defer a portion of our planned capital expenditures, as necessary. To fund our strategic growth opportunities, we evaluate the additional capital need in balance with debt capacity and equity issuances that would be intended to allow us to maintain investment grade ratings.

Credit Facilities

Liquidity is generally provided by internal cash flows and the use of our unsecured revolving credit facilities. This includes the $425 million Credit Facility, the $100 million Additional Credit Facility, and a $25 million revolving credit facility to provide swingline borrowing capability. We utilize availability under our revolving credit facilities to manage our cash flows due to the seasonality of our business and to fund capital investment. Cash on hand in excess of current operating requirements is generally used to invest in our business and reduce borrowings.

Our $425 million Credit Facility was amended and restated in May 2022 and has a maturity date of May 18, 2027. The Credit Facility includes uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points. A total of nine banks participate in the facility, with no one bank providing more than 15 percent of the total availability.

Our $100 million Additional Credit Facility was entered into in October 2022 and has a maturity date of April 28, 2024. The Additional Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

Our $25 million Swingline Facility was amended in March 2022 and has a maturity date of March 27, 2024. The Swingline Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a margin of 90.0 basis points, or (b) a base rate plus a margin of 12.5 basis points.

The following table presents additional information about borrowings under our revolving credit facilities during the year ended December 31, 2022 (in millions):

Amount outstanding at year end	$	450.0
Daily average amount outstanding	$	360.2
Maximum amount outstanding	$	450.0
Minimum amount outstanding	$	288.0

As of February 10, 2023, our availability under our revolving credit facilities was approximately $115.0 million, and there were no letters of credit outstanding.

Long-term Debt and Equity

We generally issue long-term debt to refinance other long-term debt maturities and borrowings under our revolving credit facilities, as well as to fund long-term capital investments and strategic opportunities. We have $144.7 million of debt maturing in 2023, which we intend to refinance.

We generally issue equity securities to fund long-term investment in our business. We evaluate our equity issuance needs to support our plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases. We anticipate issuing $75.0 million of common stock through our At-the-Market program in 2023.

As further discussed in Note 16 - Common Stock to the Financial Statements included herein, in November 2021 we entered into forward equity agreements in connection with a completed $373.8 million public offering of approximately 7.0 million shares of our common stock. Of the total 7.0 million shares of the common stock offered, we initially sold approximately 1.4 million shares, for $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing. During 2022 we settled our obligations under the forward sale agreement by physically delivering approximately 5.6 million shares of common stock in exchange for cash proceeds of $277.0 million, net of issuance costs. The proceeds were used to pay down borrowings under our revolving credit facility and for other general corporate purposes.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of February 10, 2023, our current ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Outlook
Fitch	A-	BBB+	Stable
Moody's	A3	Baa2	Stable
S&P	A-	BBB	Stable

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. With the exception of maturities of long-term debt, we anticipate funding these obligations through cash flows from operations. The following table summarizes our contractual cash obligations and commitments as of December 31, 2022. See additional discussion in Note 18 - Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2023	2024	2025	2026	2027	Thereafter
				(in thousands)			
Long-term debt(1)	$ 2,629,660	$ 144,660	$ 125,000	$ 300,000	$ 105,000	$ 425,000	$ 1,530,000
Finance leases	11,897	3,099	3,337	3,596	1,865	—	—
Estimated pension and other postretirement obligations(2)	58,553	12,785	11,667	11,367	11,367	11,367	N/A
Qualifying facilities liability(3)	386,095	80,750	76,393	60,360	55,393	56,665	56,534
Supply and capacity contracts(4)	2,853,614	413,374	247,468	235,828	247,028	230,299	1,479,617
Contractual interest payments on debt(5)	1,498,846	107,738	105,286	96,318	90,228	73,119	1,026,157
Commitments for significant capital projects(6)	183,895	99,452	74,368	10,075	—	—	$ —
Total Commitments(7)	$ 7,622,560	$ 861,858	$ 643,519	$ 717,544	$ 510,881	$ 796,450	$ 4,092,308

(1) Represents cash payments for long-term debt and excludes $10.8 million of debt discounts and debt issuance costs, net.
(2) We have estimated cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. The pension and other postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $386.1 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $327.8 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts (exclusive of the qualifying facilities liability discussed above). These commitments range from one to 24 years. The energy supply costs incurred under these contracts are generally recoverable through rate mechanisms approved by the MPSC, as further described in Note 3 - Regulatory Matters.
(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 5.67 percent on the outstanding balance through maturity of the credit facilities.
(6) Represents significant firm purchase commitments for construction of planned capital projects.
(7) The table above excludes potential tax payments related to uncertain tax positions as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation (See Note 18 - Commitments and Contingencies) and asset retirement obligations (AROs) (see Note 6 - Asset Retirement Obligations) as the amount and timing of cash payments may be uncertain.

Other Obligations - As a co-owner of Colstrip, we provided surety bonds of approximately $17.3 million as of December 31, 2022 and 2021, to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Stations, Colstrip Montana (the AOC) as required by the MDEQ. As costs are incurred under the AOC, the surety bonds will be reduced. We expect the surety bonds to decrease to approximately $15.6 million in 2023 once the current year operation and maintenance of remedial and closure actions are approved by the MDEQ.

CRITICAL ACCOUNTING ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances. We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates.

We have identified the policies and related procedures below that contain accounting estimates that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on our financial condition or results of operations.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 4 - Regulatory Assets and Liabilities, to the Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 14 - Employee Benefit Plans, to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Expected long-term rate of return on plan assets; and
- Mortality assumptions.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions are based upon market interest rates, past experience and management's best estimate of future economic conditions.

We set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year projected benefit cash flow from our plans. Based on this analysis as of December 31, 2022, our discount rate on both the NorthWestern Corporation pension plan and NorthWestern Energy pension plan is 5.20 percent..

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Our expected long-term rate of return on assets assumptions are 4.83 percent and 6.44 percent on the NorthWestern Corporation and NorthWestern Energy pension plan, respectively, for 2023.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate increase	0.25 %	$ 112	$ (13,786)
Discount rate decrease	(0.25)%	2,040	14,446
Rate of return on plan assets increase	0.25 %	(1,481)	N/A
Rate of return on plan assets decrease	(0.25)%	1,481	N/A

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the Consolidated Financial Statements. We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. We have unrecognized tax benefits of approximately $30.3 million as of December 31, 2022. The resolution of tax matters in a particular future period could have a material impact on our provision for income taxes, results of operations and our cash flows. See Note 12 - Income Taxes to the Consolidated Financial Statements for further discussion.

Qualifying Facilities Liability

Our electric QF liability consists of unrecoverable costs associated with contracts covered under PURPA that are part of a 2002 stipulation with the MPSC and other parties. Under the terms of these contracts, we are required to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through June 2029. Our estimated gross contractual obligation is approximately $386.1 million through June 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $327.8 million through June 2029. We maintain an electric QF liability based on the net present value (discounted at 7.75 percent) of the difference between our estimated obligations under the QFs and the fixed amounts recoverable in rates.

The liability was established based on certain assumptions and projections over the contract terms related to pricing, estimated output and recoverable amounts. Since the liability is based on projections over the next several years, actual output, changes in pricing, contract amendments and regulatory decisions relating to these facilities could significantly impact the liability and our results of operations in any given year. In assessing the liability for each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the QF contracts included in the 2002 stipulation contains variable pricing terms, which exposes us to price escalation risks. The actual contract pricing is derived from numerous internal and external data points, and is set each year through a filing with the MPSC. The annual contract pricing changes could significantly impact the liability and our results of operations, to the extent the actual price set differs from our previous estimates. The impact of historically high inflation levels experienced during 2021 and the first half of 2022 has resulted in a 20 percent decrease in the actual contract price for the 2022-2023 contract year. This contract expires after the 2023-2024 contract year. The estimated annual escalation rate for this contract is a key assumption in determining the electric QF liability. We have estimated pricing for the 2023-2024 contract year based on a combination of historical actual results and available market data and the associated impact in the numerous internal and external data points for contract pricing, resulting in an approximate 40 percent increase, reversing from the lower 2022-2023 actual contract pricing. A 10 percent change in the estimated 2023-2024 contract pricing would have impacted our pre-tax results of operations by +/- $2.7 million.

See Note 18 - Commitments and Contingencies to the Consolidated Financial Statements for further discussion.

NEW ACCOUNTING STANDARDS

See Note 2 - Significant Accounting Policies, to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks.

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities. The $425 million Credit Facility and $100 million Additional Credit Facility bear interest at rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points. In addition, we have a $25 million revolving credit facility, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest equal to (a) SOFR, plus a margin of 90.0 basis points, or (b) base rate plus a credit spread of 12.5 basis points. As of December 31, 2022, we had $450 million in borrowings under our revolving credit facilities. A 1.0 percent increase in interest rates would increase our annual interest expense by approximately $4.5 million.

Commodity Price Risk

We are exposed to commodity price risk due to our reliance on market purchases to fulfill a portion of our electric and natural gas supply requirements. We also participate in the wholesale electric market to balance our supply of power from our own generating resources. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

As part of our overall strategy for fulfilling our electric and natural gas supply requirements, we employ the use of market purchases and sales, including forward contracts. These types of contracts are included in our supply portfolios and in some instances, are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. These contracts are part of an overall portfolio approach intended to provide price stability for consumers. As a regulated utility, our exposure to market risk caused by changes in commodity prices is mitigated because these commodity costs are included in our Montana, South Dakota and Nebraska cost tracking mechanisms and are recoverable from customers subject to a regulatory review for prudency and, in Montana, a sharing mechanism.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. If counterparties seek financial protection under bankruptcy laws, we are exposed to greater financial risks. We are also exposed to counterparty credit risk related to providing transmission service to our customers under our Open Access Transmission Tariff and under gas transportation agreements. We have risk management policies in place to limit our transactions to high quality counterparties. We monitor closely the status of our counterparties and take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent registered public accounting firm and the quarterly financial information, required by this Item 8 is set forth on pages F-1 to F-50 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and accumulated and reported to management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation our principal executive officer and principal financial officer have concluded that, as of December 31, 2022, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2022. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on our evaluation, management concluded that, as of December 31, 2022, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-4.

ITEM 9B. OTHER INFORMATION

Not applicable.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Corporation's Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included under "Information about our Executive Officers" in Item 1 of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Corporation and director independence will be set forth in NorthWestern Corporation's Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information concerning fees paid to the principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34), for each of the last two years will be set forth in NorthWestern Corporation's Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Consolidated Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

CONSOLIDATED FINANCIAL STATEMENTS:

All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(2) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(c)	Colstrip Units 3&4 Interests Abandonment and Acquisition Agreement, dated as of January 16, 2023, by and between Avista Corporation and Northwestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated January 17, 2023, Commission File No. 1-10499).
3.1(a)	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated May 3, 2016 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
3.2(a)	Amended and Restated Bylaws of NorthWestern Corporation, dated May 12, 2016 (incorporated by reference to Exhibit 3.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
4.1(a)	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).
4.1(b)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.1(c)	Twenty-Eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.1(d)	Twenty-Ninth Supplemental Indenture, dated as of May 1, 2010, among NorthWestern Corporation and The Bank of New York Mellon and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.1(e)	Thirtieth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon and Philip L. Watson, as trustees under the Mortgage and Deed of Trust dated as of October 1, 1945 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.1(f)	Thirty-First Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.1(g)	Thirty-Second Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(n) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(h)	Thirty-Third Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated November 14, 2014, Commission File No. 1-10499).
4.1(i)	Thirty-Fourth Supplemental Indenture, dated as of January 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(p) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).

4.1(j)	Thirty-Fifth Supplemental Indenture, dated as of June 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2015, Commission File No. 1-10499).
4.1(k)	Thirty-Seventh Supplemental Indenture, dated as of November 1, 2017, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 8, 2017, Commission File No. 1-10499).
4.1(l)	Thirty-Eighth Supplemental Indenture, dated as of June 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated July 2, 2019, Commission File No. 1-10499).
4.1(m)	Thirty-Ninth Supplemental Indenture, dated as of September 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 20, 2019, Commission File No. 1-10499).
4.1(n)	Fortieth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.2(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).
4.2(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(c)	Ninth Supplemental Indenture, dated as of May 1, 2010, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.2(d)	Tenth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon, as trustees under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.2(e)	Eleventh Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.2(f)	Twelfth Supplemental Indenture, dated as of December 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2014, Commission File No. 1-10499).
4.2(g)	Thirteenth Supplemental Indenture, dated as of September 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated September 29, 2015, Commission File No. 1-10499).
4.2(h)	Fourteenth Supplemental Indenture, dated as of June 1, 2016, between the NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 21, 2016, Commission File No. 1-10499).
4.2(i)	Fifteenth Supplemental Indenture, dated as of September 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated October 6, 2016, Commission File No. 1-10499).
4.2(j)	Sixteenth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.3(a)	Indenture, dated as of August 1, 2016, between City of Forsyth, Rosebud County, Montana and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(b)	Loan Agreement, dated as of August 1, 2016, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2016 (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).

4.3(c)	Bond Delivery Agreement, dated as of August 1, 2016, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(d)	Thirty-Sixth Supplemental Indenture, dated as of August 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(e)	Forty-First Supplemental Indenture, dated as of March 1, 2021, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 26, 2021, Commission File No. 1-10499).
4.5*	Description of Securities
10.1(a) †	NorthWestern Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as amended April 21, 2010 (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(b) †	NorthWestern Corporation 2009 Officers Deferred Compensation Plan, as amended April 21, 2010 (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(c) †	NorthWestern Corporation Amended and Restated Equity Compensation Plan, as amended effective July 1, 2014 (incorporated by reference to Appendix A to NorthWestern Corporation's Proxy Statement for the 2014 Annual Meeting of Shareholders filed on March 7, 2014, Commission File No. 1-10499).
10.1(d) †	NorthWestern Corporation Key Employee Severance Plan 2016 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 25, 2016, Commission File No. 1-10499).
10.1(e) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2018, Commission File No. 1-10499).
10.1(f) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 15, 2019, Commission File No. 1-10499).
10.1(g) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 23, 2019, Commission File No. 1-10499).
10.1(h) †	NorthWestern Energy 2021 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2020, Commission File No. 1-10499).
10.1(i) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2020, Commission File No. 1-10499).
10.1(j) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated February 11, 2021, Commission File No. 1-10499).
10.1(k) †	NorthWestern Corporation Amended and Restated Equity Compensation Plan, as amended effective May 1, 2021 (incorporated by reference to Appendix A to NorthWestern Corporation's Proxy Statement for the 2014 Annual Meeting of Shareholders filed on March 5, 2021, Commission File No. 1-10499).
10.1(l) †	NorthWestern Energy 2022 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2021, Commission File No. 1-10499).
10.1(m) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2021, Commission File No. 1-10499).
10.1(n) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated February 10, 2022, Commission File No. 1-10499).
10.1(o) †	NorthWestern Energy 2023 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2022, Commission File No. 1-10499).
10.1(p) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2022, Commission File No. 1-10499).

10.2(a)	Commercial Paper Dealer Agreement between NorthWestern Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated, dated as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 8, 2011, Commission File No. 1-10499).
10.2(b)	Bond Purchase Agreement, dated as of October 31, 2017, between NorthWestern Corporation and initial purchasers (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on form 10-Q, dated November 2, 2017, Commission File No. 1-10499).
10.2(c)	Credit Agreement, dated September 2, 2020, among NorthWestern Corporation, as borrower; the several banks and other financial institutions or entities from time to time parties to the agreement, as lenders; BofA Securities, Inc., Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as joint lead arrangers; Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as co-syndication agents; Keybank National Association as documentation agent; and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 4, 2020, Commission File No. 1-10499).
10.2(d)	Credit Agreement, dated May 18, 2022 among Northwestern Corporation, as borrower, the several lenders from time to time parties hereto, BOFA Securities Inc., Mizuho Bank, LTD. and U.S. Bank National Association, as joint lead arrangers, Mizuho Bank, LTD and U.S. Bank National Association as co-syndication agents, Keybank National Association, as documentation agent, and Bank of America, N.A., as administrative agent, dated May 18, 2022. (incorporated by reference to Exhibit 10.1 of Northwestern Corporation's Current Report on Form 8-K, dated May 23, 2022, Commission File No. 1-10499)
10.2(e)	Credit Agreement, dated October 28, 2022 among Northwestern Corporation, as borrower, the several lenders from time to time parties hereto, Mizuho Bank, LTD., BMO Capital Markets Corp., and Keybank National Association, as joint lead arrangers, BMO Capital Markets Corp., and Keybank National Association as co-syndication agents, and Mizuho Bank, LTD., as administrative agent, dated October 28, 2022. (incorporated by reference to Exhibit 10.1 of Northwestern Corporation's Current Report on Form 8-K, dated November 3, 2022, Commission File No. 1-10499)
10.3(a)	Equity Distribution Agreement, dated April 23, 2021, between NorthWestern Corporation and J.P. Morgan Securities LLC, BofA Securities, Inc., CIBC World Markets Corp. and Credit Suisse Securities (USA) LLC, as sales agents and forward sellers; and JPMorgan Chase Bank, National Association, Bank of America N.A, Canadian Imperial Bank of Commerce and Credit Suisse Capital LLC, as forward purchasers. (incorporated by reference to Exhibit 1.1 of NorthWestern Corporation's Current Report on Form 8-K, dated April 23, 2021, Commission File No. 1-10499).
10.3(b)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of Northwestern Corporation's Current Report on Form 8-K, dated April 23, 2021, Commission File No. 1-10499)
10.3(c)	Forward Sale Agreement, dated November 16, 2021, between NorthWestern Corporation and Bank of America, N.A., as forward purchaser (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 15, 2021, Commission File No. 1-10499).
10.3(d)	Additional Forward Sale Agreement, dated November 17, 2021, between NorthWestern Corporation and Bank of America, N.A., as forward purchaser (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Current Report on Form 8-K, dated November 15, 2021, Commission File No. 1-10499).
10.4(a)	Engineering, Procurement, and Construction Contract, dated April 19, 2021, between Northwestern Energy and Burns & McDonnell Engineering Company, Inc (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
10.4(b)	Procurement Contract, dated April 19, 2021, between Northwestern Energy and Caterpillar Power Generation Systems, LLC (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
10.5(a)	Colstrip Units 3&4 Interests Abandonment and Acquisition Agreement, dated as of January 16, 2023, by and between Avista Corporation and Northwestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated January 17, 2023, Commission File No. 1-10499).
21*	Subsidiaries of NorthWestern Corporation.
23*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of President and Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1*	Certification of Brian B. Bird pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Crystal Lail pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document

101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)	

† Management contract or compensatory plan or arrangement.
* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWESTERN CORPORATION

February 17, 2023	By:	/s/ BRIAN B. BIRD
		Brian B. Bird
		President and Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Corporation, hereby severally constitute and appoint Brian B. Bird and Crystal D. Lail, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Chairman of the Board	February 17, 2023
/s/ BRIAN B. BIRD Brian B. Bird	President, Chief Executive Officer and Director (Principal Executive Officer)	February 17, 2023
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Chief Financial Officer (Principal Financial Officer)	February 17, 2023
/s/ JEFFREY B. BERZINA Jeffrey B. Berzina	Controller (Principal Accounting Officer)	February 17, 2023
/s/ ANTHONY T. CLARK Anthony T. Clark	Director	February 17, 2023
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 17, 2023
/s/ BRITT E. IDE Britt E. Ide	Director	February 17, 2023
/s/ KENT T. LARSON Kent T. Larson	Director	February 17, 2023
/s/ LINDA G. SULLIVAN Linda G. Sullivan	Director	February 17, 2023
/s/ MAHVASH YAZDI Mahvash Yazdi	Director	February 17, 2023
/s/ JEFFREY W. YINGLING Jeffrey W. Yingling	Director	February 17, 2023

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, cash flows and common shareholders' equity, for each of the three years in the period ended December 31, 2022, and the related notes (collectively, referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2023, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters - Impact of Rate Regulation on the Financial Statements-Refer to Notes 2, 3, and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by federal and state utility regulatory agencies (collectively, the “Commissions”), which have jurisdiction over the Company’s electric and natural gas distribution rates in Montana, South Dakota and Nebraska. Management has determined regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; depreciation expense; income taxes; and multiple disclosures in the notes to the financial statements.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company’s costs to provide utility service and a return on, and recovery of, the Company’s capital investment in its utility operations. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital expenditures or operating costs that management believes were prudently incurred, and (3) refunds to be provided to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments requires specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, filings made by the Company, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

- We evaluated regulatory filings and testimony for any evidence that intervenors are challenging full recovery of the cost of any capital projects or operating costs. If full recovery of project costs is being challenged by intervenors, we evaluated management's assessment of the probability of a disallowance.

- We assessed management's conclusion regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 16, 2023
We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2022, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2022, of the Company and our report dated February 16, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Annual Report on Internal Control over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 16, 2023

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues			
Electric	$ 1,106,565	$ 1,052,182	$ 940,815
Gas	371,272	320,134	257,855
Total Revenues	1,477,837	1,372,316	1,198,670
Operating Expenses			
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	492,011	425,548	306,190
Operating and maintenance	221,427	208,303	202,991
Administrative and general	113,776	101,873	94,124
Property and other taxes	192,524	173,444	179,517
Depreciation and depletion	195,020	187,467	179,644
Total Operating Expenses	1,214,758	1,096,635	962,466
Operating Income	263,079	275,681	236,204
Interest Expense, net	(100,110)	(93,674)	(96,812)
Other Income, net	19,434	8,252	4,853
Income Before Income Taxes	182,403	190,259	144,245
Income Tax Benefit (Expense)	605	(3,419)	10,970
Net Income	$ 183,008	$ 186,840	$ 155,215
Average Common Shares Outstanding	55,769	51,709	50,559
Basic Earnings per Average Common Share	$ 3.28	$ 3.61	$ 3.07
Diluted Earnings per Average Common Share	$ 3.25	$ 3.60	$ 3.06

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2022	2021	2020
Net Income	$ 183,008	$ 186,840	$ 155,215
Other comprehensive (loss) income, net of tax:			
Reclassification of net losses on derivative instruments	452	452	452
Postretirement medical liability adjustment	(982)	(436)	1,840
Foreign currency translation	(8)	(57)	87
Total Other Comprehensive (Loss) Income	(538)	(41)	2,379
Comprehensive Income	$ 182,470	$ 186,799	$ 157,594

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2022	2021
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,489	$ 2,820
Restricted cash	13,974	15,942
Accounts receivable, net	244,952	198,671
Inventories	107,359	80,614
Regulatory assets	136,009	115,541
Prepaid expenses and other	28,041	24,207
Total current assets	**538,824**	**437,795**
Property, plant, and equipment, net	5,657,480	5,247,232
Goodwill	357,586	357,586
Regulatory assets	716,570	690,686
Other noncurrent assets	47,323	47,144
Total Assets	**$ 7,317,783**	**$ 6,780,443**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 3,098	$ 2,875
Current portion of long-term debt	144,525	—
Accounts payable	201,498	115,237
Accrued expenses	250,579	233,351
Regulatory liabilities	21,145	28,179
Total current liabilities	**620,845**	**379,642**
Long-term finance leases	8,799	11,897
Long-term debt	2,474,357	2,541,478
Deferred income taxes	538,983	499,634
Noncurrent regulatory liabilities	654,213	638,760
Other noncurrent liabilities	355,403	369,319
Total Liabilities	**4,652,600**	**4,440,730**
Commitments and Contingencies (Note 18)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 63,278,307 and 59,744,130, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	633	576
Treasury stock at cost	(98,392)	(98,248)
Paid-in capital	1,999,376	1,716,227
Retained earnings	771,414	728,468
Accumulated other comprehensive loss	(7,848)	(7,310)
Total Shareholders' Equity	**2,665,183**	**2,339,713**
Total Liabilities and Shareholders' Equity	**$ 7,317,783**	**$ 6,780,443**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2022	2021	2020
OPERATING ACTIVITIES:			
Net Income	$ 183,008	$ 186,840	$ 155,215
Items not affecting cash:			
Depreciation and depletion	195,020	187,467	179,644
Amortization of debt issuance costs, discount and deferred hedge gain	5,321	5,250	4,911
Stock-based compensation costs	5,488	5,350	4,149
Equity portion of allowance for funds used during construction	(14,191)	(11,092)	(6,895)
Loss (gain) on disposition of assets	482	(47)	37
Deferred income taxes	(8,992)	525	(7,574)
Changes in current assets and liabilities:			
Accounts receivable	(46,282)	(30,442)	(824)
Inventories	(26,744)	(19,604)	(7,085)
Other current assets	(3,833)	(6,835)	(3,477)
Accounts payable	50,537	7,494	16,043
Accrued expenses	16,846	26,055	5,909
Regulatory assets	(20,512)	(69,616)	14,749
Regulatory liabilities	(7,034)	(27,674)	22,773
Other noncurrent assets	3,994	2,313	(5,396)
Other noncurrent liabilities	(25,866)	(36,006)	(20,030)
Cash Provided by Operating Activities	307,242	219,978	352,149
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(515,140)	(434,328)	(405,762)
Investment in equity securities	(1,719)	(1,505)	(42)
Cash Used in Investing Activities	(516,859)	(435,833)	(405,804)
FINANCING ACTIVITIES:			
Dividends on common stock	(140,062)	(128,483)	(120,350)
Proceeds from issuance of common stock, net	276,971	196,246	—
Issuance of long-term debt	—	99,915	150,000
Repayments on long-term debt	—	(955)	—
Line of credit borrowings (repayments), net	77,000	151,000	(67,000)
(Repayments) issuances of short-term borrowings	—	(100,000)	100,000
Treasury stock activity	603	707	(1,391)
Financing costs	(1,194)	(909)	(2,578)
Cash Provided by Financing Activities	213,318	217,521	58,681
Net Increase in Cash, Cash Equivalents, and Restricted Cash	3,701	1,666	5,026
Cash, Cash Equivalents, and Restricted Cash, beginning of period	18,762	17,096	12,070
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 22,463**	**$ 18,762**	**$ 17,096**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(in thousands, except per share data)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2019	**53,999**	**3,547**	**$ 541**	**$1,508,970**	**$ (96,015)**	**$ 635,246**	**$ (9,648)**	**$ 2,039,094**
Net income	—	—	—	—	—	155,215	—	155,215
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	87	87
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	1,840	1,840
Stock based compensation	146	35	—	4,100	(2,741)	—	—	1,359
Issuance of shares	—	(24)	—	717	681	—	—	1,398
Dividends on common stock ($2.40 per share)	—	—	—	—	—	(120,350)	—	(120,350)
Balance at December 31, 2020	**54,145**	**3,558**	**$ 541**	**$1,513,787**	**$ (98,075)**	**$ 670,111**	**$ (7,269)**	**$ 2,079,095**
Net income	—	—	—	—	—	186,840	—	186,840
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(57)	(57)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(436)	(436)
Stock based compensation	93	17	1	5,298	(971)	—	—	4,328
Issuance of shares	3,368	(29)	34	197,142	798	—	—	197,974
Dividends on common stock ($2.48 per share)	—	—	—	—	—	(128,483)	—	(128,483)
Balance at December 31, 2021	**57,606**	**3,546**	**$ 576**	**$1,716,227**	**$ (98,248)**	**$ 728,468**	**$ (7,310)**	**$ 2,339,713**
Net income	—	—	—	—	—	183,008	—	183,008
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(8)	(8)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(982)	(982)
Stock based compensation	87	16	—	7,391	(911)	—	—	6,480
Issuance of shares	5,585	(28)	57	275,758	767	—	—	276,582
Dividends on common stock ($2.52 per share)	—	—	—	—	—	(140,062)	—	(140,062)
Balance at December 31, 2022	**63,278**	**3,534**	**$ 633**	**$1,999,376**	**$ (98,392)**	**$ 771,414**	**$ (7,848)**	**$ 2,665,183**

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 764,200 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Consolidated Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The accompanying Consolidated Financial Statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the Consolidated Financial Statements. Events occurring subsequent to December 31, 2022, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

(2) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncertain tax position reserves, asset retirement obligations, regulatory assets and liabilities, allowances for uncollectible accounts, our QF liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

The Company recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.5 million and $2.3 million at December 31, 2022 and December 31, 2021, respectively. Receivables include unbilled revenues of $117.4 million and $98.1 million at December 31, 2022 and December 31, 2021, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2022	2021
Materials and supplies	$ 71,769	$ 54,137
Storage gas and fuel	35,590	26,477
Total Inventories	$ 107,359	$ 80,614

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, *Regulated Operations*. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Consolidated Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCL and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items. As of December 31, 2022, the only derivative instruments we have qualify for the normal purchases and normal sales exception.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 8 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. This rate averaged 6.4%, 6.6%, and 6.7% for Montana for 2022, 2021, and 2020, respectively. This rate averaged 6.4%, 6.4%, and 6.7% for South Dakota for 2022, 2021, and 2020, respectively. AFUDC capitalized totaled $20.2 million, $15.9 million, and $9.8 million for the years ended December 31, 2022, 2021, and 2020, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 2 to 96 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.8% for 2022, 2021, and 2020.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in noncurrent regulatory liabilities.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Accrued Expenses and other

Accrued expenses and other consisted of the following (in thousands):

	December 31,	
	2022	2021
Property taxes	$ 96,093	$ 86,168
Employee compensation, benefits, and withholdings	44,104	44,743
Customer advances	26,137	29,013
Interest	18,350	18,568
Other (none of which is individually significant)	65,895	54,859
Total Accrued Expenses	$ 250,579	$ 233,351

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31,	
	2022	2021
Pension and other employee benefits	$ 84,731	$ 96,151
Customer advances	95,393	80,780
Future QF obligation, net	49,728	64,943
Asset retirement obligations	39,096	38,350
Environmental	22,662	23,395
Other (none of which is individually significant)	63,793	65,700
Total Noncurrent Liabilities	$ 355,403	$ 369,319

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Consolidated Income Statements and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Cash paid for:			
Income taxes	$ 4,707	$ 4,330	$ 115
Interest	95,400	87,221	84,922
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	64,758	29,034	21,430
NMTC debt extinguishment included in other noncurrent assets[1]	—	18,169	—
NMTC debt extinguishment included in property, plant and equipment, net[1]	—	6,594	—
NMTC debt extinguishment included in long-term debt[1]	—	1,259	—

(1) See Note 11 - Long-Term Debt and Finance Leases for further information regarding this non-cash transaction.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Consolidated Statements of Cash Flows (in thousands):

	December 31,		
	2022	2021	2020
Cash and cash equivalents	$ 8,489	$ 2,820	$ 5,811
Restricted cash	13,974	15,942	11,285
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 22,463	$ 18,762	$ 17,096

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounting Standards Issued

There were no accounting standards adopted in the current year that had a material impact to our financial condition, results of operations, and cash flows. At this time, we are not expecting the adoption of recently issued accounting standards to have a material impact to our financial condition, results of operations, and cash flows.

(3) Regulatory Matters

Montana Rate Review

On August 8, 2022, we filed a Montana electric and natural gas rate review with the MPSC requesting an annual increase to electric and natural gas utility rates of $171.0 million and $23.0 million, respectively, detailed as follows:

Requested Revenue Increase (in millions)

	Electric	Natural Gas
Base Rates	$91.8	$20.2
Power Cost & Credit Mechanism (PCCAM)(1)	$68.1	n/a
Property Tax (tracker true-up)(1)	$11.1	$2.8
Total	$171.0	$23.0

(1) These items are flow-through costs, which represent approximately 42% of the requested electric and natural gas revenue increase.

Our electric request is based on a return on equity of 10.60% with a forecasted 2022 rate base of $2.8 billion and a capital structure of 51.98% debt and 48.02% equity. Our natural gas request is based on a return on equity of 10.60% with a forecasted 2022 rate base of $575.3 million and a capital structure of 51.98% debt and 48.02% equity.

Within this rate review filing we requested an increase to the Power Cost and Credit Mechanism (PCCAM) base rate (PCCAM Base rate) of $68.1 million, as well as structural revisions to the PCCAM mechanism to provide customers with prices that better reflect the cost of services received. We also proposed to implement a revised electric only pilot for the Fixed Cost Recovery Mechanism (FCRM) beginning July 1, 2023, or alternatively to terminate the FCRM. Our rate review filing also includes proposals for more timely cost recovery beyond the test period, including critical reliability resources, such as the Yellowstone County Generating Station, our Enhanced Wildfire Mitigation plan, and business technology maintenance costs.

On September 28, 2022, the MPSC approved the recommendations of the MPSC Staff for interim rates, subject to refund, which increased base electric rates $29.4 million, PCCAM Base rates $61.1 million, and base natural gas rates $1.7 million, effective October 1, 2022.

A hearing is scheduled to commence on April 11, 2023. Interim rates will remain in effect on a refundable basis until the MPSC issues a final order.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2020, approximately 65 MW of CREPs. While we made progress towards meeting this obligation by acquiring approximately 50 MW of CREPs, we were unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC's action as it related to waivers granted for 2015 and 2016 has been challenged legally and was fully briefed before the Montana Supreme Court.

On May 14, 2021, the Montana Governor signed a bill that eliminated the state's Renewable Portfolio Standard, including repeal of the CREP requirement. We notified the Montana Supreme Court of the repeal. We also dismissed our pending application filed with the MPSC for a waiver from full compliance for years 2017 through 2020.

On September 7, 2021, the Montana Supreme Court remanded the case challenging the 2015 and 2016 waivers to the District Court to determine whether the repeal of the CREP requirement made the petition moot. On May 9, 2022, the District Court imposed a $2.5 million penalty against us, payable to the Universal Low Income Assistance Fund in Montana, in connection with a petition filed by the MEIC challenging the MPSC's decision granting our waiver requests from CREP compliance in 2015 and 2016. The expense associated with this penalty was accrued for within our 2022 results. We filed an appeal with the Montana Supreme Court and that appeal is now fully briefed.

(4) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs, excluding the Montana PCCAM, are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2022	December 31, 2021
			(in thousands)	
Flow-through income taxes	12	Plant Lives	$ 509,038	$ 464,663
Supply costs		18 months	101,096	88,329
Pension	14	See Note 14	87,965	98,336
Excess deferred income taxes	12	Plant Lives	54,364	60,813
Employee related benefits	14	See Note 14	27,920	21,648
Deferred financing costs		See Note 11	22,620	25,636
State & local taxes & fees		1 Year	15,684	6,520
Environmental clean-up	18	Undetermined	10,963	11,262
Other		Various	22,929	29,020
Total Regulatory Assets			**$ 852,579**	**$ 806,227**
Removal cost	6	Plant Lives	$ 502,289	$ 479,294
Excess deferred income taxes	12	Plant Lives	148,989	158,047
Supply costs		1 Year	11,536	16,430
Gas storage sales		17 years	7,046	7,466
State & local taxes & fees		1 Year	2,327	3,021
Environmental clean-up		1 Year	592	508
Rates subject to refund		Not applicable	—	1,971
Other		Various	2,579	202
Total Regulatory Liabilities			**$ 675,358**	**$ 666,939**

Income Taxes

Flow-through income taxes primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, and removal costs that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. Excess deferred income tax assets and liabilities are recorded as a result of the Tax Cuts and Jobs Act and will be recovered or refunded in future rates. See Note 12 - Income Taxes for further discussion.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 7.0 percent in Montana; 7.2 percent and 7.8 percent for electric and natural gas, respectively, in South Dakota; and 8.5 percent for natural gas in Nebraska. We do not earn interest on our electric supply tracker, the PCCAM, in Montana.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension and postretirement benefit costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 6 - Asset Retirement Obligations, for further information regarding this item.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(5) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	December 31, 2022	December 31, 2021[1]
	(in thousands)	
Electric Plant	$ 5,205,788	$ 4,848,349
Natural Gas Plant	1,371,045	1,252,229
Plant acquisition adjustment[2]	686,328	686,328
Common and Other Plant	268,970	235,746
Construction work in process	311,652	294,617
Total property, plant and equipment	7,843,783	7,317,269
Less accumulated depreciation	(1,880,265)	(1,787,550)
Less accumulated amortization	(306,038)	(282,487)
Net property, plant and equipment	$ 5,657,480	$ 5,247,232

(1) The December 31, 2021 balances reported above have been reclassified to conform with the December 31, 2022 presentation of major classifications of property, plant and equipment. The reclassification has no impact on the presentation of total property, plant and equipment. These reclassifications were done in an effort to better convey the nature of these balances.

(2) The plant acquisition adjustment balance above includes our Beethoven wind project acquired in 2015, our hydro generating assets acquired in 2014, and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Net plant and equipment under finance lease were $7.2 million and $9.2 million as of December 31, 2022 and 2021, respectively, which included $7.0 million and $9.0 million as of December 31, 2022 and 2021, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

On January 16, 2023, we entered into a definitive agreement (Agreement) with Avista Corporation (Avista) to acquire Avista's 15 percent interest in each of Units 3 and 4 at the Colstrip Generating Station, a coal-fired, base-load electric generation facility located in Colstrip, Montana. As noted in the table below, we currently have a 30 percent interest in Unit 4. The Agreement provides that the purchase price will be $0 and that we will acquire Avista's interest effective December 31, 2025, subject to the satisfaction of the closing conditions contained within the agreement. Under the terms of this Agreement, we will be responsible for operating costs starting on January 1, 2026; while Avista will retain responsibility for its pre-closing share of environmental and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommission and demolition costs associated with the existing facilities that comprise Avista's interest.

The Agreement contains customary representations and warranties, covenants, and indemnification obligations, and the Agreement is subject to customary conditions and approvals, including approval from the FERC. Closing also is conditioned on our ability to enter into a new coal supply agreement for Colstrip by December 31, 2024. Such coal supply agreement must provide a sufficient amount of coal to Colstrip to permit the generation of electric power by the maximum permitted capacity of the interest in Colstrip then held by us during the period from January 1, 2026 through, December 31, 2030.

Either party may terminate the Agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing. The Agreement may be subject to the exercise by other Colstrip owners of a right of first refusal set forth in the O&O Agreement. Should any other owners exercise such rights, we intend to exercise our right of first refusal under the O&O Agreement to the fullest extent permitted, and Avista has agreed that it will not exercise its right of first refusal.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2022				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 155,567	$ 63,032	$ 51,796	$ 326,584
Accumulated depreciation	42,884	35,847	38,955	121,830
December 31, 2021				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 154,375	$ 62,865	$ 51,652	$ 324,433
Accumulated depreciation	42,102	34,629	38,453	113,805

(6) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the rate making process. We record regulatory assets and liabilities for differences in timing of asset retirement costs recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our ARO (in thousands):

	December 31,		
	2022	2021	2020
Liability at January 1,	$ 40,631	$ 45,355	$ 42,449
Accretion expense	1,853	2,233	2,070
Liabilities incurred	—	—	—
Liabilities settled	(4,004)	(2,906)	(4,061)
Revisions to cash flows	2,414	(4,051)	4,897
Liability at December 31,	$ 40,894	$ 40,631	$ 45,355

During the twelve months ended December 31, 2022 our ARO liability decreased $4.0 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities and natural gas pipeline segments. Additionally, during the twelve months ended December 31, 2022, our ARO liability increased $2.4 million related to changes in both the timing and amount of retirement cost estimates.

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 4 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2022 and 2021.

(7) Goodwill

We completed our annual goodwill impairment test as of April 1, 2022 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2022	2021
Electric	$ 243,558	$ 243,558
Natural gas	114,028	114,028
Total Goodwill	$ 357,586	$ 357,586

(8) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Consolidated Financial

Statements at December 31, 2022 and 2021. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCL. We reclassify these gains from AOCL into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2022
Interest rate contracts	Interest Expense	$ 612

A pre-tax loss of approximately $13.4 million is remaining in AOCL as of December 31, 2022, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL into interest expense during the next twelve months. These amounts relate to terminated swaps.

(9) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, accounts payable, and short-term borrowings, the carrying amount of each such item approximates fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 8 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2022	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Restricted cash equivalents	$ 12,990	$ —	$ —	$ —	$ 12,990
Rabbi trust investments	20,895	—	—	—	20,895
Total	**$ 33,885**	**$ —**	**$ —**	**$ —**	**$ 33,885**
December 31, 2021					
Restricted cash equivalents	$ 14,967	$ —	$ —	$ —	$ 14,967
Rabbi trust investments	18,234	—	—	—	18,234
Total	**$ 33,201**	**$ —**	**$ —**	**$ —**	**$ 33,201**

Restricted cash equivalents represents amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2022		December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,618,882	$ 2,316,700	$ 2,541,478	$ 2,827,336

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(10) Unsecured Credit Facilities

Credit Facilities

On May 18, 2022, we amended our existing $425 million credit facility to, among other things, change the Eurodollar rate to the secured overnight financing rate as administered by the Federal Reserve Bank of New York (SOFR) and extend the maturity date of the facility from September 2, 2023 to May 18, 2027. The amended and restated credit facility (the Primary Credit Facility) maintains the same capacity at $425 million and uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size of the facility by up to an additional $75 million. The Primary Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

On October 28, 2022, we entered into a $100 million Credit Agreement (the Additional Credit Facility) to supplement our existing $425 million revolving credit facility. The Additional Credit Facility has a maturity date of April 28, 2024. The Additional Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

On March 25, 2022, we amended our existing $25 million swingline credit facility (the Swingline Facility) to, among other things, change the Eurodollar rate to the secured overnight financing rate as administered by the Federal Reserve Bank of New York (SOFR) and extend the maturity date of the facility from March 27, 2023 to March 27, 2024. The Swingline Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a margin of 90.0 basis points, or (b) a base rate, plus a margin of 12.5 basis points.

Commitment fees for the unsecured revolving lines of credit were $0.1 million and $0.4 million for the years ended December 31, 2022 and 2021.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2022	2021
Unsecured revolving line of credit, expiring May 2027	$ 425.0	$ 425.0
Unsecured revolving line of credit, expiring April 2024	100.0	—
Unsecured revolving line of credit, expiring March 2024	25.0	25.0
	550.0	**450.0**
Amounts outstanding at December 31:		
SOFR borrowings	450.0	—
Eurodollar borrowings	—	373.0
Letters of credit	—	—
	450.0	**373.0**
Net availability as of December 31	**$ 100.0**	**$ 77.0**

The Credit Facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Credit Facility; however a default on the Credit Facility would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

(11) Long-Term Debt and Finance Leases

Long-term debt and finance leases consisted of the following (in thousands):

	Due	December 31, 2022	December 31, 2021
Unsecured Debt:			
Unsecured Revolving Line of Credit	2027	$ 425,000	$ —
Unsecured Revolving Line of Credit	2024	25,000	—
Unsecured Revolving Line of Credit	2023	—	373,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—3.21%	2030	50,000	50,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	150,000
Montana—3.21%	2030	100,000	100,000
Montana—1.00%	2024	100,000	100,000
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(10,778)	(11,182)
Total Long-Term Debt		$ 2,618,882	$ 2,541,478
Less current maturities (including associated debt issuance costs)		(144,525)	—
Total Long-Term Debt, Net of Current Maturities		$ 2,474,357	$ 2,541,478

	Due	December 31, 2022	December 31, 2021
Finance Leases:			
Total Finance Leases	Various	$ 11,897	$ 14,772
Less current maturities		(3,098)	(2,875)
Total Long-Term Finance Leases		$ 8,799	$ 11,897

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. These bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In March 2021, we issued and sold $100.0 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00 percent maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100.0 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

As of December 31, 2022, we were in compliance with our financial debt covenants.

Other Long-Term Debt

In July 2021, our two loans totaling $27.0 million associated with the New Market Tax Credit (NMTC) financing agreement were extinguished. These loans were satisfied with our $18.2 million investment in the entities created in relation to the NMTC transaction, investor forgiveness of $7.9 million for substantially all of the benefits derived from the tax credits, and cash payment of $0.9 million. In accordance with our last rate case filing in the state of Montana, the portion of the loan forgiven, less unamortized debt issuance costs of $1.3 million, was recorded as a reduction to the cost of the office building associated with the NMTC financing agreement. This cash payment is reflected within the financing activities section of our Consolidated Statement of Cash Flows for the year ended December 31, 2021; however, the remaining reduction to Long-term debt, Other noncurrent assets, and Property, plant and equipment are non-cash financing activities that are not reflected within our Consolidated Statement of Cash Flows for the year ended December 31, 2021.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and finance leases, during the next five years are $147.8 million in 2023, $128.3 million in 2024, $303.6 million in 2025, $106.9 million in 2026 and $425.0 million in 2027.

(12) Income Taxes

Income tax (benefit) expense is comprised of the following (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Federal			
Current	$ 5,024	$ 722	$ (3,396)
Deferred	(5,993)	2,626	(4,006)
Investment tax credits	(130)	(130)	(3)
State			
Current	3,363	2,172	3
Deferred	(2,869)	(1,971)	(3,568)
Income Tax (Benefit) Expense	$ (605)	$ 3,419	$ (10,970)

Our effective tax rate typically differs from the federal statutory tax rate primarily due to production tax credits and the regulatory impact of flowing through the federal and state tax benefit of repairs deductions and state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable). The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2022	2021	2020
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax, net of federal provisions	0.3	0.1	(1.1)
Flow-through repairs deductions	(12.4)	(11.5)	(16.5)
Production tax credits	(7.2)	(6.1)	(9.1)
Amortization of excess deferred income taxes	(0.9)	(0.3)	(0.7)
Prior year permanent return to accrual adjustments	(0.8)	—	(1.2)
Plant and depreciation of flow through items	(0.1)	(0.6)	0.1
Other, net	(0.2)	(0.8)	(0.1)
Effective tax rate	(0.3)%	1.8 %	(7.6)%

The table below summarizes the significant differences in income tax expense (benefit) based on the differences between our effective tax rate and the federal statutory rate (in thousands).

	Year Ended December 31,		
	2022	2021	2020
Income Before Income Taxes	$ 182,403	$ 190,259	$ 144,245
Income tax calculated at federal statutory rate	38,304	39,954	30,292
Permanent or flow through adjustments:			
State income, net of federal provisions	562	354	(1,477)
Flow-through repairs deductions	(22,665)	(21,888)	(23,828)
Production tax credits	(13,166)	(11,532)	(13,103)
Amortization of excess deferred income taxes	(1,657)	(635)	(968)
Prior year permanent return to accrual adjustments	(1,397)	(12)	(1,728)
Plant and depreciation of flow through items	(222)	(941)	121
Other, net	(364)	(1,881)	(279)
	(38,909)	(36,535)	(41,262)
Income Tax (Benefit) Expense	$ (605)	$ 3,419	$ (10,970)

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2022	2021
Production tax credit	$ 80,097	$ 75,092
Customer advances	25,119	21,271
Pension / postretirement benefits	19,291	21,435
Compensation accruals	10,306	10,612
Unbilled revenue	9,440	10,704
Environmental liability	6,009	5,704
Reserves and accruals	4,016	5,106
Interest rate hedges	3,372	3,158
Other, net	2,595	1,738
Deferred Tax Asset	**160,245**	**154,820**
Excess tax depreciation	(449,724)	(425,202)
Flow through depreciation	(106,623)	(94,616)
Goodwill amortization	(86,874)	(85,425)
Regulatory assets and other	(56,007)	(49,211)
Deferred Tax Liability	**(699,228)**	**(654,454)**
Deferred Tax Liability, net	**$ (538,983)**	**$ (499,634)**

At December 31, 2022, our total production tax credit carryforward was approximately $80.1 million. If unused, our production tax credit carryforwards will expire as follows: $8.9 million in 2036, $11.0 million in 2037, $10.9 million in 2038, $11.5 million in 2039, $13.1 million in 2040, $11.5 million in 2041, and $13.2 million in 2042. We believe it is more likely than not that sufficient taxable income will be generated to utilize these production tax credit carryforwards.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2022	2021	2020
Unrecognized Tax Benefits at January 1	$ 32,049	$ 33,491	$ 35,085
Gross increases - tax positions in prior period	—	293	120
Gross increases - tax positions in current period	—	—	—
Gross decreases - tax positions in current period	(1,719)	(1,735)	(1,714)
Lapse of statute of limitations	—	—	—
Unrecognized Tax Benefits at December 31	$ 30,330	$ 32,049	$ 33,491

Our unrecognized tax benefits include approximately $27.9 million and $28.1 million related to tax positions as of December 31, 2022 and 2021, that if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2022, we have accrued $1.4 million for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2021, we had $0.5 million accrued for the payment of interest and penalties.

Tax years 2019 and forward remain subject to examination by the Internal Revenue Service (IRS) and state taxing authorities. During the first quarter of 2023 the IRS commenced a limited scope examination of the Company's 2019 amended federal income tax return.

(13) Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	December 31,								
	2022			2021			2020		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (8)	$ —	$ (8)	$ (57)	$ —	$ (57)	$ 87	$ —	$ 87
Reclassification of net income (loss) on derivative instruments	612	(160)	452	614	(162)	452	614	(162)	452
Postretirement medical liability adjustment	(1,359)	377	(982)	(585)	149	(436)	2,463	(623)	1,840
Other comprehensive (loss) income	$ (755)	$ 217	$ (538)	$ (28)	$ (13)	$ (41)	$ 3,164	$ (785)	$ 2,379

Balances by classification included within AOCL on the Consolidated Balance Sheets are as follows, net of tax (in thousands):

	December 31,	
	2022	2021
Foreign currency translation	$ 1,435	$ 1,443
Derivative instruments designated as cash flow hedges	(9,825)	(10,277)
Postretirement medical plans	542	1,524
Accumulated other comprehensive loss	$ (7,848)	$ (7,310)

The following table displays the changes in AOCL by component, net of tax (in thousands):

		Year Ended December 31, 2022			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,277)	$ 1,524	$ 1,443	$ (7,310)
Other comprehensive loss before reclassifications		—	—	(8)	(8)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(982)	—	(982)
Net current-period other comprehensive income (loss)		452	(982)	(8)	(538)
Ending Balance		$ (9,825)	$ 542	$ 1,435	$ (7,848)

		Year Ended December 31, 2021			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,729)	$ 1,960	$ 1,500	$ (7,269)
Other comprehensive loss before reclassifications		—	—	(57)	(57)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(436)	—	(436)
Net current-period other comprehensive income (loss)		452	(436)	(57)	(41)
Ending Balance		$ (10,277)	$ 1,524	$ 1,443	$ (7,310)

(14) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plans' funded status is recognized as an asset or liability in our Consolidated Financial Statements. See Note 4 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits December 31, 2022	Pension Benefits December 31, 2021	Other Postretirement Benefits December 31, 2022	Other Postretirement Benefits December 31, 2021
Change in benefit obligation:				
Obligation at beginning of period	$ 696,802	$ 820,979	$ 17,308	$ 19,146
Service cost	10,223	12,994	351	407
Interest cost	18,787	18,759	358	317
Actuarial loss	(176,389)	(28,905)	(99)	415
Settlements(1)	—	(93,488)	—	—
Benefits paid	(27,625)	(33,537)	(2,511)	(2,977)
Benefit Obligation at End of Period	$ 521,798	$ 696,802	$ 15,407	$ 17,308
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 605,499	$ 688,456	$ 25,289	$ 23,096
Return on plan assets	(144,535)	33,868	(4,098)	3,349
Employer contributions	8,200	10,200	1,375	1,821
Settlements(1)	—	(93,488)	—	—
Benefits paid	(27,625)	(33,537)	(2,511)	(2,977)
Fair value of plan assets at end of period	$ 441,539	$ 605,499	$ 20,055	$ 25,289
Funded Status	$ (80,259)	$ (91,303)	$ 4,648	$ 7,981
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	7,195	8,297	8,831	11,914
Total Assets	7,195	8,297	8,831	11,914
Current liability	(11,200)	(11,200)	(1,585)	(1,575)
Noncurrent liability	(76,254)	(88,400)	(2,598)	(2,358)
Total Liabilities	(87,454)	(99,600)	(4,183)	(3,933)
Net amount recognized	$ (80,259)	$ (91,303)	$ 4,648	$ 7,981
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	(116)	1,870
Net actuarial loss	(54,383)	(62,448)	(3,123)	1,366
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	—	(95)
Net actuarial gain	—	—	1,046	2,500
Total	$ (54,383)	$ (62,448)	$ (2,193)	$ 5,641

(1) In December 2021, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 1,062 NorthWestern Energy Pension Plan participants. We purchased the contract with $93.5 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2022. This transaction settled $93.5 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2021, we recorded a non-cash, non-operating settlement charge of $11.3 million. This charge is recorded within other income, net on the Consolidated Statements of Income. As discussed within Note 4 – Regulatory Assets and Liabilities, this charge was deferred as a regulatory asset on the Consolidated Balance Sheets, with a corresponding decrease to operating and maintenance expense on the Consolidated Statements of Income.

The actuarial gain/loss is primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts. The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2022	2021
Projected benefit obligation	$ 474.9	$ 636.3
Accumulated benefit obligation	474.9	636.3
Fair value of plan assets	388.7	537.9

As of December 31, 2022, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2022	2021	2020	2022	2021	2020
Components of Net Periodic Benefit Cost						
Service cost	$ 10,223	$ 12,994	$ 11,116	$ 351	$ 407	$ 370
Interest cost	18,787	18,759	22,840	359	327	492
Expected return on plan assets	(24,173)	(27,061)	(26,162)	(1,047)	(919)	(983)
Amortization of prior service cost (credit)	—	—	—	(1,891)	(1,835)	(1,882)
Recognized actuarial loss (gain)	383	6,536	5,028	(897)	(898)	(61)
Settlement loss recognized(1)	—	11,291	—	—	—	390
Net Periodic Benefit Cost (Credit)	$ 5,220	$ 22,519	$ 12,822	$ (3,125)	$ (2,918)	$ (1,674)
Regulatory deferral of net periodic benefit cost(2)	2,307	(13,308)	(2,100)	—	—	—
Previously deferred costs recognized(2)	—	—	71	292	709	861
Net Periodic Benefit Cost Recognized	$ 7,527	$ 9,211	$ 10,793	$ (2,833)	$ (2,209)	$ (813)

(1) Settlement loss is related to partial annuitization of NorthWestern Energy Pension Plan effective December 1, 2021.
(2) Net periodic benefit costs for pension and postretirement benefit plans are recognized for financial reporting based on the authorization of each regulatory jurisdiction in which we operate. A portion of these costs are recorded in regulatory assets and recognized in the Consolidated Statements of Income as those costs are recovered through customer rates.

For the years ended December 31, 2022, 2021, and 2020, Service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other income (expense), net on the Consolidated Statements of Income.

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2022 and 2021. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets. During 2022, the plan's actuary conducted an experience study to review five years of plan experience and update these assumptions.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in the discount rate during 2022 decreased our projected benefit obligation by approximately $179.2 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 6.44 percent and increased our assumption on the NorthWestern Corporation Pension Plan to 4.83 percent for 2023.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2022	2021	2020	2022	2021	2020
Discount rate	5.20 %	2.65-2.75 %	2.20-2.30 %	5.15-5.20 %	2.35-2.40 %	1.80 %
Expected rate of return on assets	2.66-4.26	3.01-4.17	3.45-4.49	4.23	4.08	4.71
Long-term rate of increase in compensation levels (non-union)	4.00	2.84	2.84	4.00	2.84	2.84
Long-term rate of increase in compensation levels (union)	4.00	2.00	2.00	4.00	2.00	2.00
Interest crediting rate	3.30-6.00	3.30-6.00	3.30-6.00	N/A	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00 percent fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, Prudent Man Rule of the Employee Retirement Income Security Act of 1974 and liability-based considerations. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- Pension Plan portfolio risk is described by volatility in the funded status of the Plans;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan’s aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the pension plans overall funded status, (such assets will be described as Liability Hedging Fixed Income assets);
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Private real estate and broad global opportunistic fixed income asset classes can provide diversification to both equity and liability hedging fixed income investments and that a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy Pension Plan investments over full market cycles;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;

- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5 percent, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2022	2021	2022	2021	2022	2021
Fixed income securities	45.0 %	55.0 %	90.0 %	90.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	4.0	1.0	1.0	—	—
Opportunistic fixed income	5.5	—	—	—	—	—
Global equities	44.0	41.0	9.0	9.0	60.0	60.0
Private real estate	5.5	—	—	—	—	—

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2022	2021	2022	2021	2022	2021
Cash and cash equivalents	— %	0.1 %	1.1 %	0.4 %	0.6 %	0.1 %
Fixed income securities	44.5	53.8	88.6	89.5	36.7	33.7
Non-U.S. fixed income securities	—	3.9	0.9	0.9	—	—
Opportunistic fixed income	5.5	—	—	—	—	—
Global equities	43.4	42.2	9.4	9.2	62.7	66.2
Private real estate	6.6	—	—	—	—	—
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. The guidelines allow for a transition to targets over time as assets are reallocated to newly-approved asset classes of opportunistic fixed income and private real estate. Debt securities consist of U.S. and international instruments including emerging markets and high yield instruments, as well as government, corporate, asset backed and mortgage backed securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Equity, real estate and fixed income portfolios may be comprised of both active and passive management strategies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks. We also invest in global equities with exposure to developing and emerging markets. Equity investments may also be diversified across investment styles such as growth and value. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes. Real estate investments will consist of global equity or debt interests in tangible property consisting of land, buildings, and other improvements in commercial and residential sectors.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Additional funding relief was passed in the American Rescue Plan Act of 2021, providing for longer amortization and interest rate smoothing, which we elected to use. We expect to continue to make contributions to the pension plans in 2023 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension costs for 2022, 2021 and 2020 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2022	2021	2020
NorthWestern Energy Pension Plan (MT)	$ 7,000	$ 9,000	$ 10,201
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200	1,200
	$ 8,200	$ 10,200	$ 11,401

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2023	31,014	2,520
2024	32,448	2,079
2025	33,904	1,584
2026	34,908	1,511
2027	35,490	1,372
2028-2032	185,939	6,060

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2022, 2021 and 2020 were $12.3 million, $11.8 million, and $11.1 million, respectively.

(15) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2022, there were 655,565 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals. These awards contain both market- and performance-based components. The performance goals are independent of each other and equally weighted, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance unit awards. The fair value of the earnings per share component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2022	2021
Risk-free interest rate	1.82 %	0.19 %
Expected life, in years	3	3
Expected volatility	28.2% to 38.8%	28.2% to 38.5%
Dividend yield	4.5 %	4.3 %

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2022, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	162,523	$ 58.76
Granted	92,970	51.61
Vested	(58,889)	73.13
Forfeited	(2,197)	54.25
Remaining nonvested grants	194,407	$ 51.04

We recognized compensation expense of $4.2 million, $3.9 million, and $2.2 million for the years ended December 31, 2022, 2021, and 2020, respectively, and related income tax benefit of $(1.3) million, $(0.2) million, and $(0.6) million for the years ended December 31, 2022, 2021, and 2020, respectively. As of December 31, 2022, we had $6.4 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.3 million, $4.2 million, and $5.1 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. Awards granted before 2022 are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Awards granted in 2022 and retirement/ retention restricted share awards granted in the future no longer contain this performance measure, instead these awards will vest after five full calendar years if the employee remains employed during that service period. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2022, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	87,319	$ 49.63
Granted	25,360	47.04
Vested	(13,394)	52.20
Forfeited	—	—
Remaining nonvested grants	99,285	$ 48.62

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100 percent of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years).

Following is a summary of the components of DSUs issued and compensation expense attributable to the DSUs (in millions, except DSU amounts):

	December 31,		
	2022	2021	2020
DSUs Issued	12,109	18,741	21,434
Compensation expense	$ 0.7	$ 1.1	$ 1.5
Change in value of shares	0.1	1.3	(2.9)
Total compensation expense (benefit)	$ 0.8	$ 2.4	$ (1.4)
DSUs withdrawn	4,022	186,137	613
Value of DSUs withdrawn	$ 0.2	$ 12.1	$ 0.1

(16) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of the common stock, 2,865,957 shares are reserved for the incentive plan awards. For further detail of grants under this plan see Note 15 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 16,120 and 16,880 during the years ended December 31, 2022 and 2021, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Issuance of Common Stock

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. This is a three-year agreement, expiring on February 11, 2024. During the twelve months ended December 31, 2021, we issued 1,966,117 shares of our common stock under the ATM program at an average price of $63.81, for net proceeds of $124.0 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We did not issue equity through the ATM program during 2022.

On November 17, 2021, we announced a registered public offering of 6,074,767 shares of our common stock at a public offering price of $53.50 per share, for an issuance amount of $325.0 million. In conjunction with this offering, we granted the underwriters an option to purchase up to 911,215 additional shares, which was subsequently exercised in full, for an additional issuance amount of $48.8 million. Of the total 6,985,982 shares of common stock offered, we initially sold 1,401,869 shares, $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing. The remaining 5,584,113 shares were sold under forward sales agreements which provide for settlement on a settlement date or dates to be specified at our discretion, but which is expected to occur on or prior to February 28, 2023. The cumulative shares issued under the forward sales agreement is limited to one and one-half times the base number of shares within the agreement, or 8,376,170 shares.

The forward sales agreements were physically settled with common shares issued by us. On settlement dates, we issued shares of common stock to the forward purchaser at the then-applicable forward sale price and received issuance proceeds at that time. The forward sale price was initially $51.8950 per share, which was subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and was subject to decrease on certain dates specified in the forward sale agreement by amounts related to expected dividends on shares of common stock during the term of the forward sale agreement.

On June 24, 2022, we partially settled the forward sale agreement by physically delivering 2,004,483 shares of common stock in exchange for cash proceeds of $99.9 million, net of issuance costs. On September 21, 2022, we partially settled the forward sale agreement by physically delivering 1,618,932 shares of common stock in exchange for cash proceeds of approximately $80.0 million, net of issuance costs. On November 28, 2022, we partially settled the forward sale agreement by physically delivering 1,409,702 shares of common stock in exchange for cash proceeds of approximately $70.0 million, net of issuance costs. On December 21, 2022, we settled the remaining portion of the forward sale agreement by physically delivering 550,996 shares of common stock in exchange for cash proceeds of approximately $27.1 million, net of issuance costs. The proceeds were used to pay down borrowings under our revolving credit facility and for other general corporate purposes.

The forward sale agreement was classified as an equity transaction because it was indexed to our common stock, physical settlement was within our control, and the other requirements necessary for equity classification were met. As a result of the equity classification, no gain or loss was recognized within earnings due to subsequent changes in the fair value of the forward sales agreement. If the average price of our common stock exceeds the adjusted forward sales price during a quarterly period, the forward sales agreement could have a dilutive effect on earnings per share.

(17) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if unvested shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	December 31,		
	2022	2021	2020
Basic computation	55,769,156	51,709,229	50,559,208
Dilutive effect of			
Performance and restricted share awards(1)	26,621	111,940	145,181
Forward equity sale(2)	496,333	51,057	—
Diluted computation	56,292,110	51,872,226	50,704,389

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award.
(2) Forward equity shares are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the forward sale agreement.

As of December 31, 2022, there were 21,459 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations.

(18) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. As of December 31, 2022, our estimated gross contractual obligation related to these contracts was approximately $386.1 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $327.8 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Fuel, purchased power and direct transmission expense and Electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in Other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2022	2021
Beginning QF liability	$ 64,943	$ 81,379
Settlements(1)	(20,076)	(22,497)
Interest expense	4,861	6,061
Ending QF liability	$ 49,728	$ 64,943

(1) The primary components of the change in settlement amounts includes (i) a lower periodic adjustment of $5.4 million due to actual price escalation, which was less than previously modeled; (ii) higher costs of approximately $0.8 million, due to a $1.8 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $2.6 million reduction in costs in the prior period; and (iii) a prior year favorable adjustment of approximately $7.0 million decreasing the QF liability associated with a one-time clarification in contract term.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2023	$ 80,750	$ 61,280	$ 19,470
2024	76,393	60,706	15,687
2025	60,360	52,950	7,410
2026	55,393	46,274	9,119
2027	56,665	46,668	9,997
Thereafter	56,534	59,895	(3,361)
Total(1)	$ 386,095	$ 327,773	$ 58,322

(1) This net unrecoverable amount represents the undiscounted difference between the total gross obligations and recoverable amounts. The ending QF liability in the table above represents the present value of this net unrecoverable amount.

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in Fuel, purchased power and direct transmission expense in the Consolidated Statements of Income and were approximately $328.0 million, $286.7 million and $206.6 million for the years ended December 31, 2022, 2021, and 2020, respectively. As of December 31, 2022, our commitments under these contracts were $413.4 million in 2023, $247.5 million in 2024, $235.8 million in 2025, $247.0 million in 2026, $230.3 million in 2027, and $1.5 billion thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $24.5 million between 2023 and 2040. These commitments are not reflected in our Consolidated Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us or for which we are responsible, is estimated to range between $21.6 million to $32.7 million. As of December 31, 2022, we had a reserve of approximately $26.4 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

The following summarizes the change in our environmental liability (in thousands):

	December 31,		
	2022	2021	2020
Liability at January 1,	$ 26,866	$ 28,895	$ 30,276
Deductions	(2,033)	(2,799)	(2,977)
Charged to costs and expense	1,534	770	1,596
Liability at December 31,	$ 26,367	$ 26,866	$ 28,895

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

Manufactured Gas Plants - Approximately $20.5 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Agriculture and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2022, the reserve for remediation costs at this site was approximately $7.8 million, and we estimate that approximately $2.8 million of this amount will be incurred through 2025.

Nebraska - We own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and field work was completed in 2022. We submitted a Remedial Investigation Report (RI Report) summarizing the work completed to MDEQ and are awaiting its review and comments as to any additional field work. We expect the MDEQ review of the RI Report to be concluded in 2023, and any additional field work to commence following that.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership, we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party has assumed the lead role at the site and has expressed its intention to submit a voluntary remediation plan for the Missoula site to MDEQ. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of GHG including, most significantly, carbon dioxide (CO_2) and methane emissions from natural gas. These actions include legislative proposals, Executive, Congressional and EPA actions at the federal level, state level activity, investor activism and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny. We have joint ownership interests in four coal-fired electric generating plants, all of which other companies operate. Despite efforts over the years, Congress has not passed any federal climate change legislation regarding GHG emissions from coal-fired plants. While, Section 111(d) of the Clean Air Act (CAA) confers authority on EPA and the states to regulate emissions, including

GHGs, from existing stationary sources, no regulation has survived judicial review. In 2022 EPA opened a docket to collect public input to guide the EPA's next effort to reduce GHG emissions from new and existing coal fired plants and natural gas operations. EPA indicated that it intends to use this non-rulemaking docket to gather perspectives from a broad group of stakeholders in advance of an expected proposed rulemaking. Ultimately, we cannot predict whether or how future GHG emission legislation, regulations, investor activism or litigation will impact our plants. As GHG regulations are implemented, it could result in additional compliance costs impacting our future results of operations and financial position, if such costs are not recovered through regulated rates. These could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions may not be available within a timeframe consistent with the implementation of any such requirements. Physical impacts of climate change also may present potential risks for severe weather, such as droughts, fires, floods, wind, ice storms and tornadoes, in the locations where we operate or have interests. These potential risks may impact costs for electric and natural gas supply and maintenance of generation, distribution, and transmission facilities. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact our customers.

***Clean Air Act Rules and Associated Emission Control Equipment Expenditures* -** The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

***Regional Haze Rules* -** In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

The states of Montana, North Dakota and South Dakota have developed and submitted to the EPA, for its approval, their respective State Implementation Plans (SIP) for Regional Haze compliance. While these states, among others, did not meet the EPA's July 31, 2021 submission deadline, they were all submitted in 2022. The Montana SIP as drafted and submitted to EPA does not call for additional controls for our interest in Colstrip Unit 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility. Similarly, the draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are finalized and approved by EPA, the potential remains that installation of additional emissions controls might be required at these facilities.

***Jointly Owned Plants* -** We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

***Other* -** We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating with PNWS in early 2016 to purchase the output from 21 of its proposed facilities pursuant to our standard QF-1 Tariff, which is applicable to projects no larger than 3 MWs.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for that category of solar projects, which included the projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had both submitted a signed power purchase agreement and had executed an interconnection agreement with us by June 16, 2016. Although we had signed four power purchase agreements with PNWS as of that date, we had not entered into interconnection agreements with PNWS for any of those projects. As a result, none of the PNWS projects in Montana qualified for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and a judicial declaration that some or all of the 21 proposed power purchase agreements it had proposed to us were in effect despite the MPSC's Order. We removed the state lawsuit to the United States District Court for the District of Montana.

On August 31, 2021, the District Court ruled that the four agreements were valid and enforceable contracts and that we breached the agreements on June 16, 2016 by refusing to go forward with the projects in spite of the MPSC's Orders. On December 15, 2021, after a three-day trial, the jury determined that PNWS had sustained $0.5 million in damages and the judge subsequently entered judgment against us in that amount.

The appeal is fully briefed at the Ninth Circuit. Oral arguments were held on February 8, 2023.

Talen Montana Bankruptcy

On May 9, 2022 Talen Energy Supply, LLC (Talen Energy) along with 71 affiliated entities, filed bankruptcy in Houston, Texas, seeking reorganization under Chapter 11 (the Talen Bankruptcy). Talen Montana, LLC (Talen) was one of the affiliated entities that filed bankruptcy and is included as a part of the Talen Bankruptcy. Talen is one of the co-owners of Colstrip Units 1, 2 and 3, and the operator of Units 3 and 4. The Talen Bankruptcy filing, along with the automatic stay under §362 of the Bankruptcy Code, has affected pending legal proceedings in which both NorthWestern and Talen are involved, including the State of Montana-Riverbed Rents Litigation, the Colstrip Arbitration and Litigation, and the Colstrip Coal Dust Litigation, as described in the individual matters below. On December 15, 2022 the bankruptcy court confirmed Talen’s Chapter 11 Plan. Apart from the delays of legal proceedings due to the automatic stay, we have not noted any detrimental effect on the operation or Colstrip Units 3 and 4 caused by Talen’s bankruptcy.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State’s Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen’s, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen’s and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history. In 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach “at least from the head of the first waterfall to the foot of the last” was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State’s Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). On August 1, 2018, the Federal District Court granted our and Talen’s motions to dismiss the State’s Complaint as it pertains to the Great Falls Reach. A bench trial before the Federal District Court commenced January 4, 2022 and concluded on January 18, 2022, which addressed the issue of navigability.

Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

The Talen Bankruptcy filing in May 2022, and resulting automatic stay, resulted in a hold on this case, including a hold on any decision regarding navigability. In September 2022, the parties stipulated and the Bankruptcy Court issued its Order modifying the stay to permit the Federal District Court to issue its decision on the navigability phase of the case. We are awaiting the Federal District Court decision on navigability. The damages phase of the case remains stayed.

We dispute the State's claims and intend to continue to vigorously defend the lawsuit. At this time, we cannot predict an outcome. If the Federal District Court determines the riverbeds are navigable under the remaining six facilities that were not dismissed and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $3.8 million commencing when we acquired the facilities in November 2014. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Colstrip Arbitration and Litigation

The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them, the Ownership and Operation Agreement (O&O Agreement). Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we have incurred additional operating costs with respect to our interest in Unit 4 and may experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

While the pendency of the lawsuits involving Montana legislation that would have impacted the arbitration process and Talen's Bankruptcy delayed commencement of the Arbitration proceedings, and thus delayed resolution of the issues we raised when we commenced arbitration, since resolution of the lawsuits, the owners have initiated efforts to identify arbitrators pursuant to their stipulation entered in the Talen bankruptcy proceeding. Despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed upon process for the Arbitration and a commercial resolution to the owners disagreements.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen, the operator of the Colstrip Units 1, 2, 3 and 4 (Colstrip), in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with Colstrip. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, as well as the other owners of Colstrip, and Westmoreland Rosebud Mining LLC, as defendants. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties. Talen's bankruptcy and resulting automatic stay prevents the plaintiffs from pursuing their claims against Talen, but does not automatically prevent the plaintiffs from pursuing their claims against the other defendants. Based on a stipulation and Bankruptcy Court order, Talen's bankruptcy stay, as it concerns this matter, was lifted on February 13, 2023.

Since this lawsuit remains in its early stages, we are unable to predict outcomes or estimate a range of reasonably possible losses.

BNSF Demands for Indemnity and Remediation Costs

NorthWestern has received a demand for indemnity from BNSF Railway Company (BNSF) for past and future environmental investigation and remediation costs incurred by BNSF at one of the three operable units at the Anaconda Copper Mining (ACM) Smelter and Refinery Superfund Site, located near Great Falls, Montana. Smelter and refining operations at the site commenced in 1893 and continued until 1980.

According to U.S. EPA, the smelter and refining operations have contaminated soil, groundwater and surface water resources around the site with lead, arsenic and other metal wastes. ARCO (Atlantic Richfield Company) initiated reclamation and maintenance activities in the 1980s and 1990s. Between 2002 and 2008, the EPA conducted several site investigations. In March 2011, the EPA placed the ACM Smelter and Refinery Site on the Superfund program's National Priority List. The Superfund Site is 427 acres and contains three operable units: Operable Unit 1 (consisting of five subsections including the Railroad Corridor and four other "areas of interest"), Operable Unit 2 (the former smelter and refinery site), and Operable Unit 3 (the Missouri River that flows along the south sides of Operable Units 1 and 2).

NorthWestern owns property in the Railroad Corridor sub-section of Operable Unit 1. BNSF claims it is entitled to indemnity and contribution from NorthWestern for the costs it has and will incur to investigate and remediate contamination in Operable Unit 1. BNSF reports it has incurred in excess of $4.4 million, pending final resolution of response and oversight costs incurred by government agencies (EPA and Montana DEQ), in investigative and other response costs associated with Operable Unit 1, and that in the future it will incur additional costs to implement the final remedy for Operable Unit 1. In the Record of Decision (ROD) for Operable Unit 1 issued on August 21, 2021, the EPA estimated the costs to implement the selected remedies for the Railroad Corridor will be approximately $4.1 million. In the ROD, the EPA also estimated the costs to implement the selected remedy (including institutional controls) for the four "areas of interest" in Operable Unit 1 would be approximately $1.8 million, with annual operating costs of ten thousand dollars. We are evaluating BNSF's claim and are unable at this time to predict outcomes or estimate a range of reasonably possible losses.

Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In our opinion, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and do not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

We currently provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which include single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to our customers in our Montana and South Dakota jurisdictions. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to our customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue for the twelve months ended by major source and customer class (in millions):

December 31, 2022	Electric	Natural Gas	Total
Montana	357.4	152.3	509.7
South Dakota	69.8	39.2	109.0
Nebraska	—	35.8	35.8
Residential	**427.2**	**227.3**	**654.5**
Montana	368.6	79.3	447.9
South Dakota	108.2	28.5	136.7
Nebraska	—	22.1	22.1
Commercial	**476.8**	**129.9**	**606.7**
Industrial	39.8	1.5	41.3
Lighting, Governmental, Irrigation, and Interdepartmental	31.0	1.9	32.9
Total Customer Revenues	**974.8**	**360.6**	**1,335.4**
Other Tariff and Contract Based Revenues	85.7	38.3	124.0
Total Revenue from Contracts with Customers	**1,060.5**	**398.9**	**1,459.4**
Regulatory amortization	46.1	(27.7)	18.4
Total Revenues	**$ 1,106.6**	**$ 371.2**	**$ 1,477.8**

December 31, 2021	Electric	Natural Gas	Total
Montana	334.6	126.0	460.6
South Dakota	65.4	26.6	92.0
Nebraska	—	21.0	21.0
Residential	**400.0**	**173.6**	**573.6**
Montana	356.7	64.7	421.4
South Dakota	102.5	19.1	121.6
Nebraska	—	11.4	11.4
Commercial	**459.2**	**95.2**	**554.4**
Industrial	37.9	1.1	39.0
Lighting, Governmental, Irrigation, and Interdepartmental	32.1	1.4	33.5
Total Customer Revenues	**929.2**	**271.3**	**1,200.5**
Other Tariff and Contract Based Revenues	89.5	36.8	126.3
Total Revenue from Contracts with Customers	**1,018.7**	**308.1**	**1,326.8**
Regulatory amortization	33.5	12.0	45.5
Total Revenues	**$ 1,052.2**	**$ 320.1**	**$ 1,372.3**

December 31, 2020	Electric	Natural Gas	Total
Montana	320.8	103.5	424.3
South Dakota	66.6	21.5	88.1
Nebraska	—	16.9	16.9
Residential	**387.4**	**141.9**	**529.3**
Montana	338.3	51.3	389.6
South Dakota	101.1	14.3	115.4
Nebraska	—	8.1	8.1
Commercial	**439.4**	**73.7**	**513.1**
Industrial	36.8	0.9	37.7
Lighting, Governmental, Irrigation, and Interdepartmental	31.8	0.9	32.7
Total Customer Revenues	**895.4**	**217.4**	**1,112.8**
Other Tariff and Contract Based Revenues	58.5	35.5	94.0
Total Revenue from Contracts with Customers	**953.9**	**252.9**	**1,206.8**
Regulatory amortization	(13.1)	5.0	(8.1)
Total Revenues	**$ 940.8**	**$ 257.9**	**$ 1,198.7**

(20) Segment and Related Information

Our reportable business segments are primarily engaged in the electric and natural gas business. The remainder of our operations are presented as other, which primarily consists of unallocated corporate costs and unregulated activity.

We evaluate the performance of these segments based on utility margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions.

Financial data for the business segments for the twelve months ended are as follows (in thousands):

December 31, 2022	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,106,565	$ 371,272	$ —	$ —	$ 1,477,837
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	324,434	167,577	—	—	492,011
Utility Margin	782,131	203,695	—	—	985,826
Operating and maintenance	167,798	53,629	—	—	221,427
Administrative and general	82,405	31,002	369	—	113,776
Property and other taxes	149,781	42,734	9	—	192,524
Depreciation and depletion	162,404	32,616	—	—	195,020
Operating income (loss)	219,743	43,714	(378)	—	263,079
Interest expense, net	(74,420)	(13,030)	(12,660)	—	(100,110)
Other income, net	12,491	6,399	544	—	19,434
Income tax benefit (expense)	798	(3,108)	2,915	—	605
Net income (loss)	$ 158,612	$ 33,975	$ (9,579)	$ —	$ 183,008
Total assets	$ 5,892,508	$ 1,418,059	$ 7,216	$ —	$ 7,317,783
Capital expenditures	$ 409,707	$ 105,433	$ —	$ —	$ 515,140

December 31, 2021	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,052,182	$ 320,134	$ —	$ —	$ 1,372,316
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	294,820	130,728	—	—	425,548
Utility margin	757,362	189,406	—	—	946,768
Operating and maintenance	156,383	51,920	—	—	208,303
Administrative and general	72,641	27,550	1,682	—	101,873
Property and other taxes	134,910	38,526	8	—	173,444
Depreciation and depletion	154,626	32,841	—	—	187,467
Operating income (loss)	238,802	38,569	(1,690)	—	275,681
Interest expense, net	(82,678)	(6,083)	(4,913)	—	(93,674)
Other income, net	3,676	3,046	1,530	—	8,252
Income tax (expense) benefit	(2,512)	(2,640)	1,733	—	(3,419)
Net income (loss)	$ 157,288	$ 32,892	$ (3,340)	$ —	$ 186,840
Total assets	$ 5,432,578	$ 1,342,031	$ 5,834	$ —	$ 6,780,443
Capital expenditures	$ 354,775	$ 79,553	$ —	$ —	$ 434,328

December 31, 2020	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 940,815	$ 257,855	$ —	$ —	$ 1,198,670
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	236,581	69,609	—	—	306,190
Utility margin	704,234	188,246	—	—	892,480
Operating and maintenance	149,220	53,771	—	—	202,991
Administrative and general	69,602	26,311	(1,789)	—	94,124
Property and other taxes	140,621	38,887	9	—	179,517
Depreciation and depletion	147,968	31,676	—	—	179,644
Operating income	196,823	37,601	1,780	—	236,204
Interest expense, net	(85,487)	(6,341)	(4,984)	—	(96,812)
Other income (expense), net	4,867	2,704	(2,718)	—	4,853
Income tax benefit (expense)	11,282	(2,426)	2,114	—	10,970
Net income (loss)	$ 127,485	$ 31,538	$ (3,808)	$ —	$ 155,215
Total assets	$ 5,126,589	$ 1,251,240	$ 11,620	$ —	$ 6,389,449
Capital expenditures	$ 324,369	$ 81,393	$ —	$ —	$ 405,762

(21) Fourth Quarter Financial Data (Unaudited)

Our fourth quarter financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Amounts presented are in thousands, except per share data:

	Three Months Ended December 31,	
	2022	2021
Operating revenues	$ 425,283	$ 347,341
Operating income	83,228	79,990
Net income	$ 66,743	$ 51,336
Average common shares outstanding	58,345	53,293
Income per average common share:		
Basic	$ 1.16	$ 0.96
Diluted	$ 1.16	$ 0.96